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Evaluation of Central Heating Plant at Rickenbacker Air National Guard Base

by
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This study analyzed emissions tests of the Rickenbacker CHP, and evaluated the CHP equipment and equipment procedures to help Rickenbacker facility engineers achieve and maintain efficient and compliant CHP performance. Performance procedures developed by this study enabled the Rickenbacker CHP to achieve a particulate emission rate 70 percent lower than OEPA standards, and to maintain compliance until the scheduled replacement of the base CHP.

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In 1979, when the 301st Air Refueling Wing was deactivated, base operations at Rickenbacker Air Force Base were transferred to the Ohio Air National Guard. Reduced military activities on the base lowered heating demand on the central heating system, causing operation and maintenance problems. Continuous operation of boilers below capacity imbalanced the combustion system, resulting in corrosive operating conditions, high energy costs, and increased particulate emissions. Consequently, the Rickenbacker central heating plant (CHP) failed an Ohio Environmental Protection Agency (OPEA) compliance test, and was liable to received a large punitive fine.

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FOREWORD

This project was sponsored by Rickenbacker Air National Guard Base (ANGB), Ohio, under MIPR No. AG-7-001, dated 21 October 1986. LTC Richard Haines, 121st COS/DE, Base Civil Engineer, served as technical monitor.

This work was performed by the Energy and Utility Systems Division (ES), of the U.S. Army Construction Engineering Research Laboratory (USACERL). The principal investigator was Martin J. Savoie. Special acknowledgement is given to Rickenbacker ANGB personnel Jerome Gaietto and Jerry Michaels for their assistance in field investigations. Dr. Gilbert R. Williamson is Chief of USACERL-ES. The USACERL technical editor was William J. Wolfe, Information Management Office.

COL Everett R. Thomas is Commander and Director of USACERL, and Dr. L.R. Shaffer is Technical Director.

CONTENTS

FIGURES

TABLES

EVALUATION OF CENTRAL HEATING PLANT AT RICKENBACKER AIR NATIONAL GUARD BASE

1 INTRODUCTION

Background

Rickenbacker Air Force Base underwent a mission change in 1979 when the 301st Air Refueling Wing was deactivated, ending the presence of active duty units at the base. In 1980, base operations were transferred to the Ohio Air National Guard and the base name was changed to Rickenbacker Air National Guard Base (ANGB). This mission change greatly reduced military activities on the base, and consequently lowered the heating demand on the central heating system. This resulted in severe operation and maintenance problems. The low airflows of boilers continuously operating below capacity caused an imbalance in the combustion system and resulted in corrosive operating conditions, high energy costs, and an increase in particulate emissions.

These conditions caused the central heating plant (CHP) to fail an air pollution compliance test in 1985. Although the test showed the CHP was only marginally out of compliance, the State of Ohio Environmental Protection Agency (OEPA) registered a complaint against Rickenbacker for this violation and for operating the CHP with an expired state permit. After three years of deliberations, the Ohio EPA decided not to issue a permit, and charged the base with particulate emission violations. Based on these violations, the OEPA imposed a large fine against Rickenbacker.

The OEPA fine coincided with a study initiated by Rickenbacker to evaluate thermal energy supply alternatives at the base. The study, conducted by Venture Engineering, Inc., Columbus, OH, determined the operation of the CHP to be uneconomical, and recommended that the central heating system be replaced by separate gas-fired heating systems located in individual buildings.

Facility engineers at Rickenbacker agreed with the recommendation; however, it was estimated that the new heating system would not be available for at least 3 years. This study was initiated to review the combustion conditions during the failed compliance test, to determine why the CHP had failed, and to identify methods that would assure compliance until the new heating system is in operation.

Objective

The objective of this study was to investigate the Rickenbacker CHP combustion and air pollution compliance problems and to provide guidance on maintaining efficient and compliant CHP operation at a cost justified by the CHP's expected 3-year life.

Approach

Emissions tests performed in 1980 and 1985 were reviewed for accuracy and compliance with standard procedures. The fireside portion of the heating system was evaluated to identify potential problems in equipment and equipment operation. This evaluation focused on stokers, furnaces, convective

sections, combustion controls, coal specifications, and air pollution control equipment. Combustion and emissions tests were made to determine optimal conditions for heating plant operation to ensure continued compliance with OEPA air pollution regulations throughout the remaining life of the plant. Installation personnel were instructed on recommended changes in operation and equipment maintenance.

Scope

Although the O&M procedures presented for the BAHCO scrubber are unique to Rickenbacker ANGB, the operations and maintenance (O&M) optimization procedures for the combustion equipment are applicable to most coal-fired stoker boiler systems.

Mode of Technology Transfer

It is recommended that the operation and maintenance concepts for combustion and air pollution control equipment be incorporated into the Rickenbacker ANGB central heating plant procedures.

It is also recommended that these concepts be incorporated into Technical Manual (TM) 50650, *Central Boiler Plants* (Headquarters, Department of the Army [HQDA], Washington, DC, October 1989).

2 SITE DESCRIPTION

Thermal energy needs for Rickenbacker ANGB are provided primarily by high temperature hot water (HTHW) produced by a coal-fired central heating plant. Air pollution control for the central heating plant is provided by a BAHCO wet scrubbing system.

Thermal Energy Use

Rickenbacker ANGB's primary function is to provide support to the 121st Tactical Fighter Wing, 160th Air Refueling Group, and 907th Tactical Airlift. Most of the thermal energy is used to provide space heating for aircraft hangars, military housing, support facilities and administrative offices.

Figure 1 is a general map of the installation showing the HTHW distribution system lines. Most of the facilities are located north of the heating plant, with the exception of the 900 Area buildings. The distribution system serves about 60 buildings for a total area of about 1.6 million sq ft.[1] HTHW is supplied to these areas by two main trunk lines, a 1-in. line for the north area and a 6-in. line for the 900 Area buildings. The 8-mi distribution system resides about 50 percent above ground, and 50 percent below ground in direct buried conduit.

Almost all the thermal energy is consumed in space heating, primarily by hot water radiators. About 50 heat exchangers or converters on the HTHW distribution system produce low temperature hot water or steam. Sixteen buildings are heated directly by HTHW. Two hangars, with areas greater than 80,000 sq ft, make up about 30 percent of the total thermal demand. A small amount of steam is used for food preparation at the two dining halls and for equipment cleaning at the maintenance facilities. Because of the low thermal demand during the summer months, the central heating plant is shut down from July through September each year. The typical fuel consumption for Rickenbacker ANGB is about 11,000 to 12,000 tons of coal per year. Table 1 shows the seasonal coal use as a percent of the annual use.

Central Heating Plant

Figure 2 schematically shows the central heating plant combustion air flow system. Prior to reassignment as a National Guard Base, the system contained six traveling-grate spreader-stoker high temperature hot water generators (HTWG). Currently, only four remain operational. To be consistent with base nomenclature, this report will refer to the HTWGs as boilers. Boilers No. 4, 6, and 7 are rated for output at 30 MBtu/hr and No. 8 is rated at 60 MBtu/hr. The smaller units, manufactured by Riley Stoker, were installed in the 1950's and No. 8, manufactured by Detroit Stoker, was installed in 1976. Boiler No. 4 is only used for emergency backup. The units burn bituminous coal with a sulfur content of between 3 and 4 percent.

Each boiler draws combustion air from a vent located about 2 ft above the boiler house roof. The combustion air is drawn by a forced draft fan through an air preheater located at the boiler outlet (breeching). The air preheater is simply a vertical enclosure around the outside of the breeching containing several baffle plates.

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[1] A metric conversion table is included on p. 60.

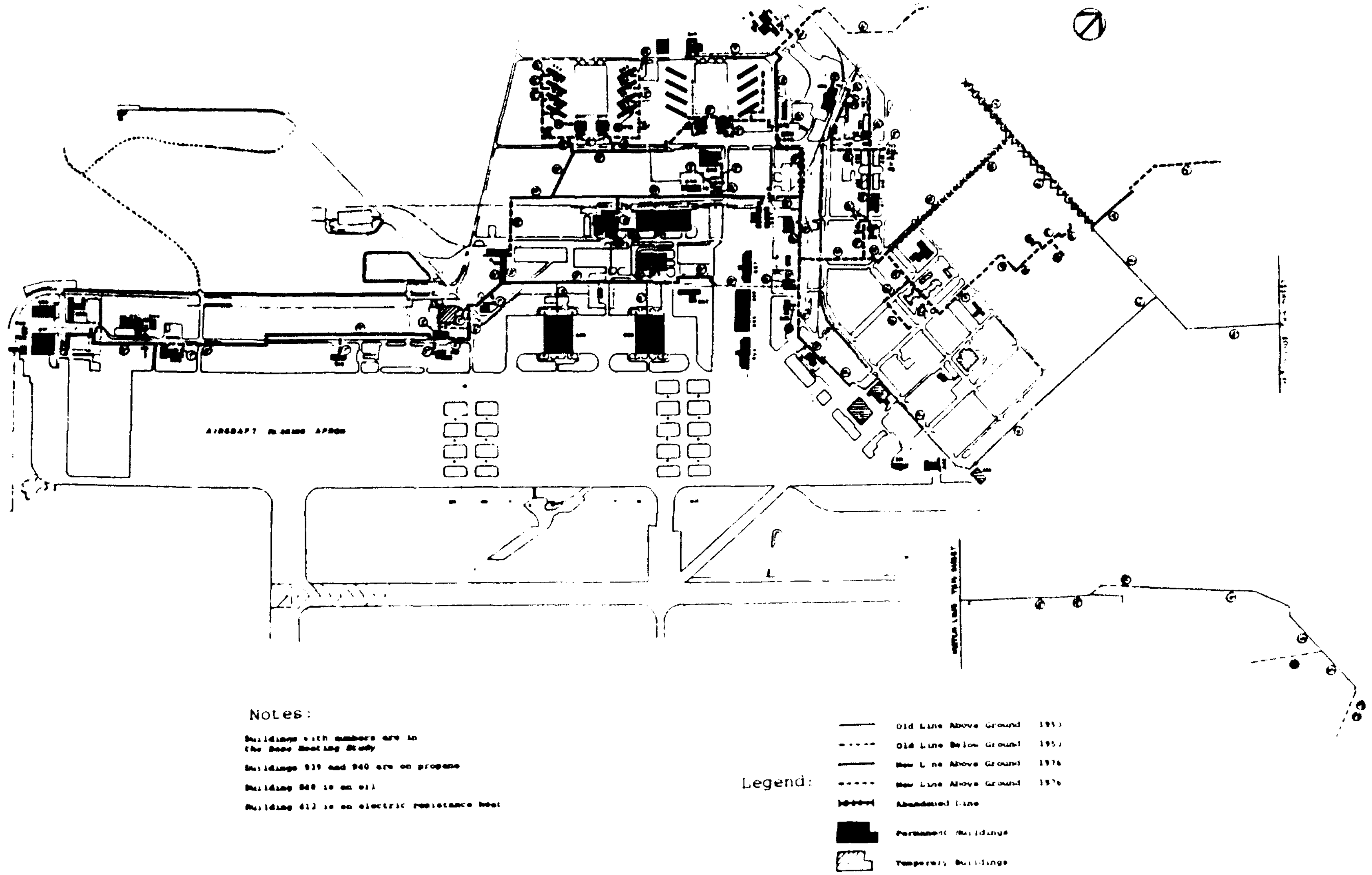


Figure 1. Rickenbacker ANGB distribution system map.

Table 1

Seasonal Coal Use

Season	Fuel Use (%)
Winter (Jan-Mar)	65
Spring (Apr-Jun)	9
Summer (Jul-Sep)	0
Fall (Oct-Dec)	26

The heated air then enters an air plenum (windbox), which distributes the air under the stoker grates (Figure 3). Additional combustion air is introduced as overfire air in the furnace chamber to increase turbulence and retention time, which in turn improves combustion efficiency. The overfire air is provided by a separate fan that pulls air from the boiler house operating floor.

Combustion flue gases are then pulled by an induced draft fan through the air preheater and a multiple cyclone collector (mechanical collector), which removes fly ash particles from the flue gas to protect the induced draft fan and to reduce particulate emissions.

At this point, the flue gas from all the boilers are pulled through one breeching by an induced-draft fan that directs the flue gas to a common mechanical collector and wet scrubbing system. Each boiler also has a bypass stack, used when the scrubber system requires shutdown. The common mechanical collector also removes particulates to protect the scrubber-induced draft fan and to reduce particulates entering the scrubber. A makeup air stack is located in the common breeching to supply the correct airflow through the scrubber.

The BAHCO wet scrubber is a unique system designed to remove both particulate and sulfur-oxide emissions and was a major concern of this project.

BAHCO Scrubber System

The Research Cottrell/BAHCO system was installed in 1976 as part of a program to demonstrate the viability of combined particulate and sulfur-dioxide removal systems for industrial-scale coal-fired boilers using midwestern high sulfur coal. This was a highly unusual double-orifice scrubber system, the first of its kind installed in the United States and only one of three such units ever built. Simpler and more economical systems developed in the mid-1970s quickly displaced the Research Cottrell/BAHCO systems.

The scrubber system was originally designed to handle up to 108,000 ACFM of flue gas at 475 °F, approximately equivalent to a coal firing rate of 200 MBtu per hour. Since the scrubbing system was installed, base heating demand has fallen; consequently two of the six hot water generators have been retired.

USEPA-sponsored performance evaluations were conducted by Research Cottrell and the U.S. Air Force from 1976 to 1977. From 1979 to 1980, the Air Force cooperated with an EPA-sponsored study of sulfur dioxide continuous monitors for scrubber systems conducted by PEDCo Environmental, Inc.

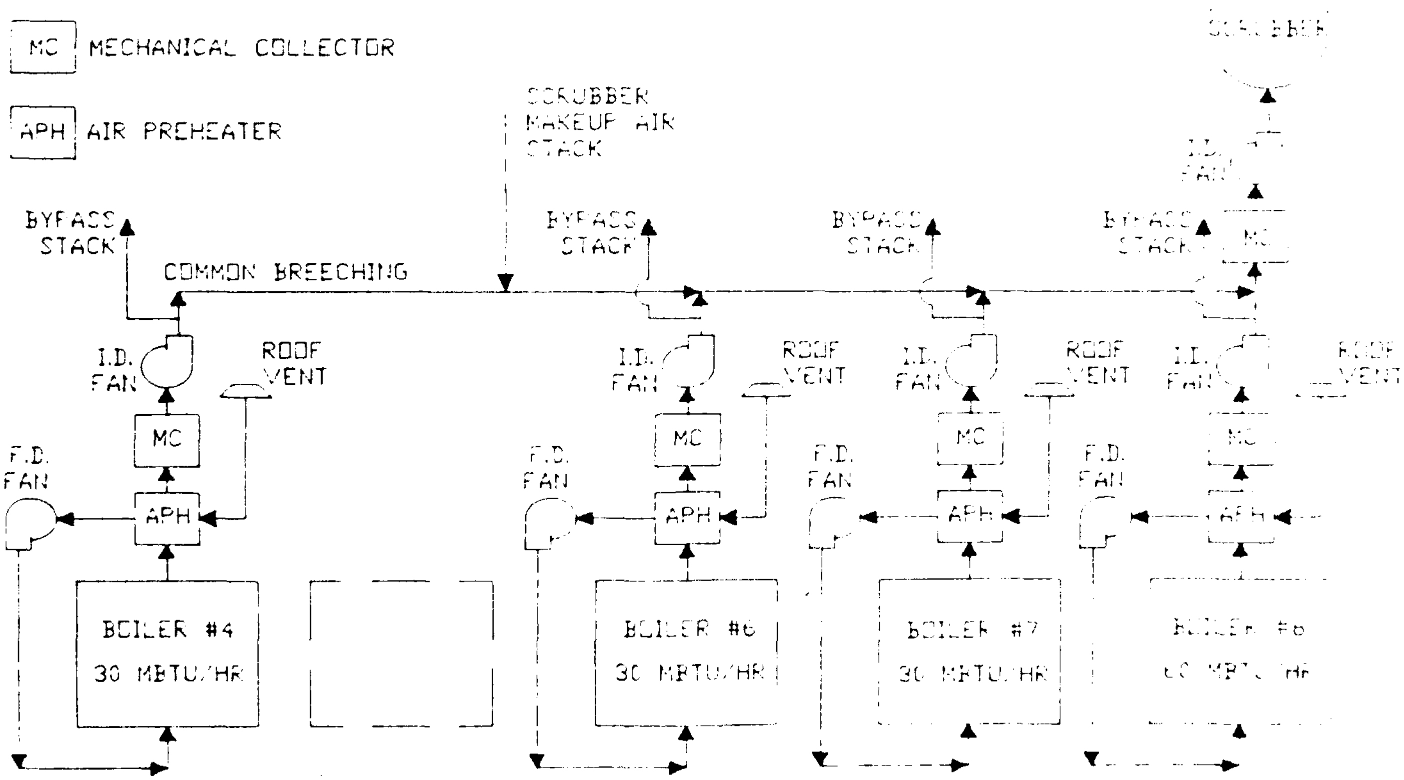


Figure 2. CHP combustion air flow schematic.

Effluent gas from each online hot water generator is collected in a common flue on the facility roof. This flue includes a tempering air damper that draws in ambient air to maintain adequate flue gas flow rates for both the mechanical collector and double orifice scrubber. Figure 5 shows the "makeup" air supply line that was included in the document titled, 'EPA Evaluation of BAHCO Industrial Boiler Scrubber System at Rickenbacker AFB."[2] However, it should be noted that this damper is not immediately upstream of the mechanical collector as indicated in Figure 5. It is located after the boiler number 5 inlet duct, approximately 40 ft upstream of the boiler 6 inlet duct.

The booster fan provides the necessary energy for the gas stream to overcome the flow resistance in the scrubber tower. The inlet static pressure can be varied simply by adjusting the booster fan inlet dampers. It normally remains in the range of 12- to 18-in. water column (sometimes denoted "in. w.c."), although it may rise as high as 30 in. w.c. This pressure is measured at a point shown as port #1 on Figure 4. The gas stream entering the scrubber is forced downward toward the scrubbing liquor contained in the scrubber sump. While the gas stream passes over the liquor and turns upwards to pass up the center opening, liquor droplets are formed and entrained in the gas stream. Some fly ash particles adhere to these droplets during passage through this first stage. The efficiency of initial particle collection is related to the total static pressure drop across this first stage. The static pressure drop is determined by subtracting the static pressure drop at port #2, shown in Figure 4, from the inlet static pressure drop determined at port #1. Some of the entrained liquor is collected above the first stage and passes into the first stage seal tank and then back to the lime tank (via the first stage level tank).

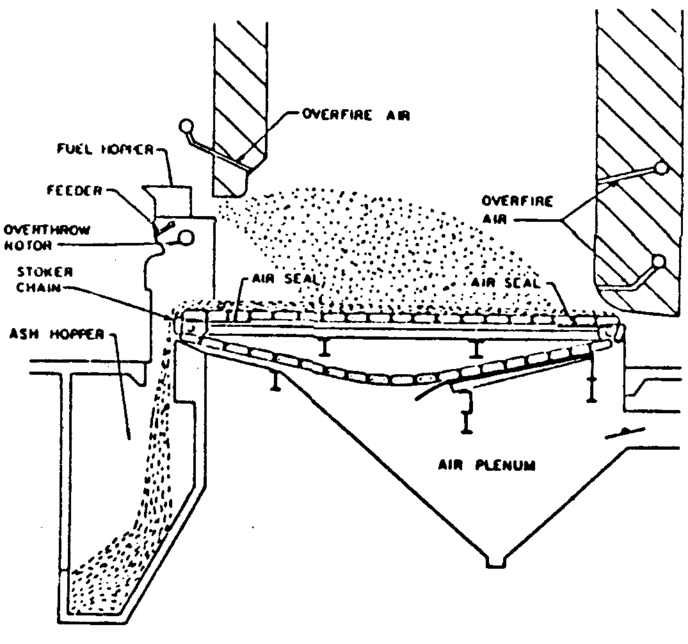


Figure 3. Traveling-grate spreader-stoker schematic.

[2] E.L. Biedell et al., *EPA Evaluation of Bahco Industrial Boiler Scrubber Systems at Rickenbacker AFB*, EPA-600/7-78-115 (USEPA, Washington, DC, June 1978).

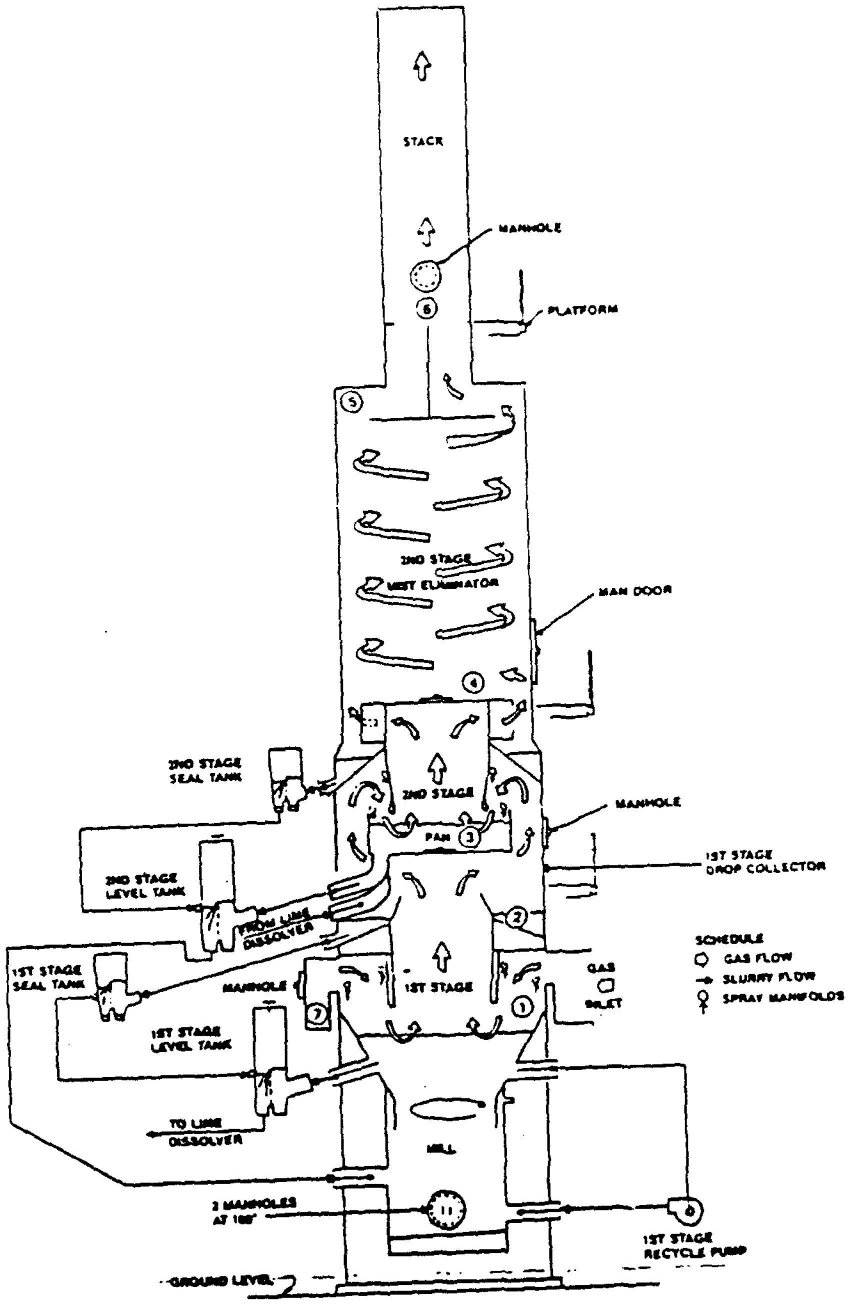


Figure 4. General flowchart of scrubber system.

Following the first stage, the gas stream is again forced to turn downwards toward a liquor tank (termed "pan" in Figure 4). The liquor droplets formed and entrained during gas passage through this stage allow for some additional particulate matter removal. The static pressure drop across this stage is determined by subtracting the static pressure measured at port #3 in the demister section from the static pressure determined at port #2 shown in Figure 4.

The gas exiting the second stage enters centrifugal vanes which impart a spinning action to the gas stream. Some droplet collection occurs in this large chamber at the top of the scrubber tower. This liquor is collected in a sump immediately below the centrifugal vane horizontal discharges.

From the second stage seal tank, the liquor is drained into the first stage seal tank and eventually to the scrubber sump (termed "mill" in Figure 4). The gas stream leaving the mist eliminator section of the scrubber tower passes around a circular baffle plate, around flow straighteners (not shown in either figure), and up the stack.

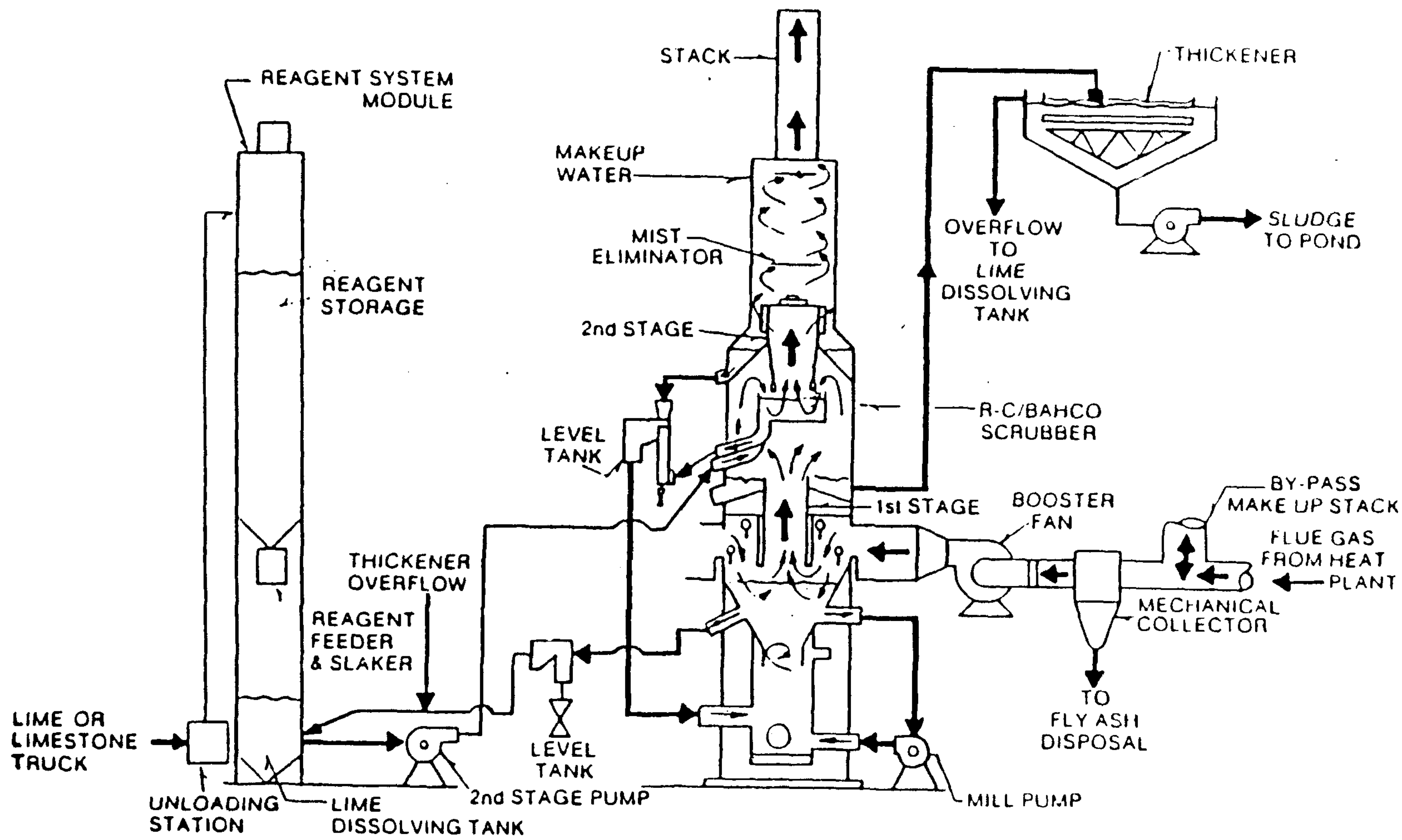


Figure 5. Scrubber tower general arrangement.

3 ANALYSIS OF PAST COMPLIANCE TESTS

Particulate Sampling Background

The USEPA standard method for measuring particulate pollutants from fossil fuel boilers (EPA Method 5, "Determination of Particulate Emissions from Stationary Sources") contains very specific procedures on sampling equipment, data collection, data analysis, and quality control.[3] Failure to follow these procedures may render an emissions test invalid.

In isokinetic sampling, a probe is inserted into the stack and a small portion of the flue gas is withdrawn. The sample is withdrawn at the same velocity as the flue gas to provide a uniform sample of the particulates in the stack. The velocities are matched by using a velocity probe, which is inserted in the stack along with the sample probe and a gas meter. Test procedures require an isokinetic flow rate between 90 and 110 percent. The flue gas sample is filtered through a fine fiberglass filter paper and a glass impinger filled with water to remove particulates from the flue gas.

The weight of the particulates collected is measured in pounds and divided by the sampling time in hours, or the gas flow rate. This gives an emission rate in pounds per hour (lb/hr) or in pounds per dry standard cubic feet (lb/dscf). This emission rate is then converted to pounds per million Btu (lb/MBtu) by multiplying by the boiler heat input per hour, or by the USEPA F-Factor method. This conversion to (lb/MBtu) is as important as the original (lb/hr) emission rate, since OEPA regulations are based on the ratio of emissions to heat input. An inaccurate measurement of the heat input on the low side would result in a higher calculated emission rate.

The heat input to a coal-fired boiler can be very difficult to determine because of the nonhomogeneous properties of coal. There are, however, several methods available to calculate heat input and to provide cross checking of the values. Typically, heat input is calculated directly from fuel input. It can also be calculated indirectly by the feedwater flow rate, steam output flow chart, and steam output integrator.

The F-Factor method uses the particulate concentration from the stack test, an F-Factor that estimates the ratio of the volumetric flow rate of the flue gas and the rate of heat input, and a correction factor for excess air. The F-Factor is estimated from the volume of gas produced by the stoichiometric combustion of the fuel, divided by the gross calorific value of the fuel. The F-Factor is multiplied by the ratio of percentage of oxygen in the air to the difference between the percentage in air and in the flue gas (to correct the gas volume for excess air).

Emissions based on the F-Factor are derived from the following equation:

$$E = c_s \times F_d\ \underbrace{[20.9/(20.9-\%O_{2d})]}_{\text{[excess air correction factor]}} \qquad \text{[Eq 1]}$$

where:
E = emissions in lb/MBtu
c = particulate concentration in lb/dscf
Fd = F-Factor (dry basis) in dscf/MBtu
$\%O_2d$ = oxygen content (dry basis) in percent

The F-factor may become inaccurate if outside or room air infiltrates into the flue gas stream. This infiltration is typical of coal-fired boilers because the furnace and ducting are under negative pressure.

[3] G.J. Aldina and J.A. Jahnke, *Source Sampling for Particulates*, APTI Course 450 Student Manual, EPA 450/2-79-006 (USEPA Air Pollution Training Institute, December 1979).

Infiltration on the Rickenbacker system is higher than normal because the scrubber system requires "makeup air" to maintain flue gas flow near its optimum operating efficiency. The F-Factor does not account for carbon loss, radiation loss, or manufacturer's margin losses. The omission of these losses tends to increase the calculation of particulate emissions.

Substituting typical values in the correction factor shows the importance of the excess air correction factor. For example, if the flue gas O_2 content at the boiler outlet is 10 percent, the correction factor is 1.92. However, 100 ft downstream where the stack sample is made, the flue gas O_2 content is 15 percent, which gives a correction factor of 3.54. The increased O_2, caused by outside air infiltration into the flue gas stream, would indicate an 84 percent increase in emissions. This calculation is not entirely correct, because the volume of air would also increase, lowering the c_s value. However, if the flue gas stream is stratified or there is leakage near the sampling probe, the oxygen content could be artificially high, causing high calculated emissions.

In most cases, emission rates are calculated using a standard F-Factor, based on an average value according to fuel type. The standard F-Factor for bituminous coal is 9820 dscf/MBtu input. In cases where the higher heating value of the fuel is much higher than the standard F-Factor, the standard F-Factor may result in high calculated emission rates. A fuel specific or coal F-Factor can be developed and used in place of the standard F-Factor, if the Ultimate Analysis of the fuel is known.

1980 Test by PEDCo

In March 1980, a series of sulfur dioxide and particulate emission tests were conducted by PEDCo Environmental, Inc. on the Rickenbacker ANGB central heating plant. The primary purpose of the tests was to collect continuous sulfur dioxide (SO_2) emission information to support the development of new source performance standards for industrial boilers. The tests were not intended to be used for regulatory compliance. Although the tests showed compliance with the USEPA standard for SO_2 at that time, the particulate tests were not as successful.

The average particulate emission rate was 0.26 lb/MBtu, higher than the OEPA requirement of about 0.16 lb/MBtu. With an average scrubber inlet loading of 0.33 lb/MBtu, the particulate removal efficiency of the scrubber was only 21.2 percent.

Similar low particulate removal efficiencies were also noted during earlier testing of the unit by Research-Cottrell, Inc. in 1978. The low efficiencies were attributed to two causes: (1) bypassing of flue gas during high system pressure drops and low slurry flows and (2) re-entrainment of particle droplets during low pressure drops. However, these two conditions were controllable as long as the unit was maintained within the proper operating limits.

The PEDCo test had noted a plugging of their SO_2 continuous emissions monitor (CEM) during their tests. Because the CEM is located in the scrubber outlet stack, it may have had trouble with either bypassing or re-entrainment. PEDCo also noted a problem with "rainout," another term for re-entrainment. However, the lack of operations data prevents confirmation of the causes of the low particulate removal efficiencies.

A review of the available data did provide information that appears to render this test invalid. Appendix A contains statements from Charles M. Schmidt, Schmidt Associates, Inc., Cleveland and Dr. John Richards, Richards Engineering, that provide several reasons supporting this. The most notable problem with the PEDCo test was with the flue gas samples of O_2 and CO_2. These readings showed inconsistencies: CO_2 ranged from 0.4 to 8 percent and O_2 ranged from 7.4 to 19.6 percent. The calculated particulate emissions values did not agree with the USEPA F-Factor methods using the same values.

1985 Test by Stilson

In April 1986, a series of SO_2 and particulate emission tests were conducted by Stilson Laboratories, Inc., Columbus, OH, to determine compliance with Ohio EPA regulations for SO_2 and particulate emissions. As in the PEDCo tests, SO_2 emissions did meet the OEPA requirements. The particulate emissions were also out of compliance, but only marginally. Table 2 shows the results of the Stilson tests for particulate emissions. Particulate emissions were estimated using both the measured fuel input and a calculated fuel input. The calculated input method was used because the unusually high efficiencies that resulted from the measured input (over 100 percent in one case) indicate that measured heat input may have been incorrect.

The OEPA emission limits for Rickenbacker ANGB, according to Rule AP-3-11, was 0.16 lb/MBtu. After 1 October 1983, particulate emission limits were determined by OEPA regulation OAC-3745-17. Figure 6 shows this methodology. The P-1 curve is used for coal-fired boiler plants. For the new standard, the emission limit would be 0.183, based on a plant capacity of 120 MBtu/hr and 90 percent efficiency. Even at a more modest efficiency of 75 percent, the emission limit would be 0.174. So, either way the limits are calculated, the plant appeared to be only marginally out of compliance.

This test was also reviewed, and the test data indicate that the test is not valid according to OEPA test procedures. Appendix A contains statements from Charles M. Schmidt, Schmidt Associates, Inc. and Dr. John Richards, Richards Engineering, that provide several reasons supporting this. The most notable problems were inaccurate coal input measurements, extremely high O_2 readings, and poor isokinetic flow rates. Coal input was based on the assumption that the coal auger supplies the same amount of coal to boiler No. 8 every 1 1/2 minutes, even though coal density changes with coal size. Coal input calculations for boilers No. 6 and 7 were based on similar assumptions. Furthermore, O_2 and CO_2 readings were identical for all three tests. This is highly unusual for a coal-fired boiler, especially over a 2-day period.

The reported isokinetic flow rates for the tests were 65.8, 90.9, and 90.3 percent, respectively. The first test is well out of the 90 to 110 percent range and the other two are marginally acceptable.

Although there was much evidence to indicate that the Rickenbacker ANGB central heating plant was not out of compliance, the base decided to perform a thorough evaluation of the plant to identify and correct any potential problems to ensure the plant's compliance and energy efficiency for the its limited remaining life.

Table 2

Particulate Emission Results - 1985

Test No.	Test Date	Heat Out MBtu/hr	Coal Input lb/hr	Coal Input MBtu/hr	Efficiency,% Heat Out / Heat In	Calculated(1) Heat Input MBtu	Particulate Emission lb/hr	Particulate Emission MBtu input As Measured	Particulate Emission MBtu input As Calc
1-2	3/20/86	82.1	8,800	94.06	87.3	102.6	21.93	0.233	0.21
2-1	3/21/86	78.8	8,777	95.50	82.5	98.5	18.29	0.192	0.19
3-1	3/21/86	79.4	6,863	76.29	104.1	99.3	13.43	0.176	0.14
AVERAGE		80.1	8,147	88.6	90.4	100.1	17.88	0.20	0.18

	Gas Flow ACFM	Temp. °F	Moisture % Vol	CO^2 %	O^2 %
1-2	65,800	107	5.0	2.0	17.0
2-1	62,100	112	7.5	2.0	17.0
3-1	64,700	112	7.0	2.0	17.0
AVERAGE	64,200	110.3	6.5	2.0	17.0

COAL ANALYSIS, AS RECEIVED

	Moisture %	Ash %	Volatile Material %	Fixed Carbon %	Sulfur %	Heat Value Btu/LB
1-2	11.78	8.74	40.61	38.87	2.50	10,689
2-1	9.77	9.91	40.90	39.43	2.32	10,880
3-1	10.74	7.32	41.48	40.45	2.29	11,117
AVERAGE	10.76	8.66	41.0	39.58	2.37	10,895

(1) This column shows the heat input based on the heat output as measured by the water flow rate and temperature rise from the generators divided by an assumed thermal efficiency of 80 percent. This calculated heat input is probably more accurate than that determined by the coal rates using volume measurements.

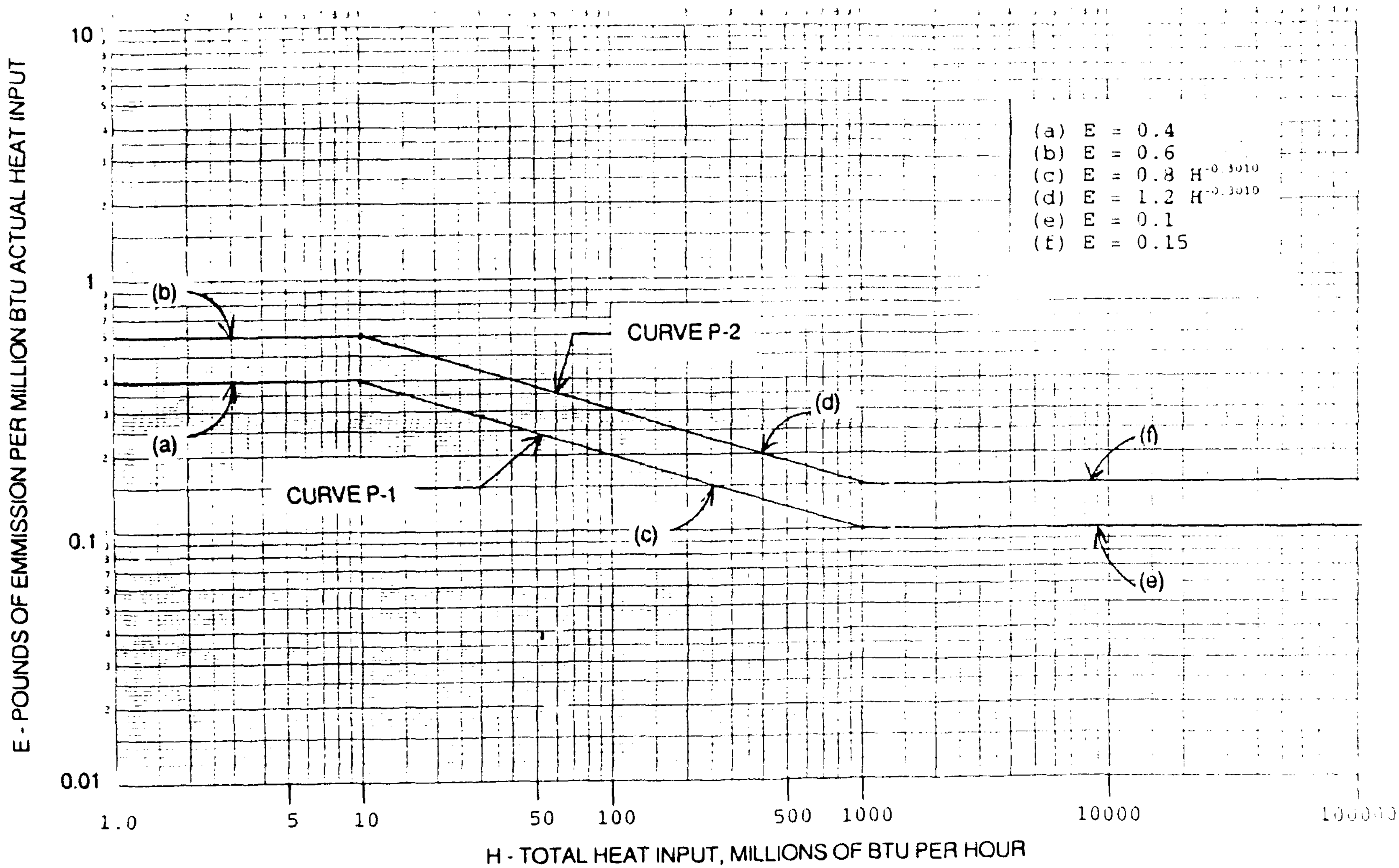


Figure 6. OEPA particulate emissions limit curve.

4 SYSTEM INSPECTION AND TESTING

Although previous tests did not prove conclusively that the Rickenbacker ANGB central heating plant was out of compliance with OEPA regulations, a thorough investigation was made of the plant's operation and maintenance condition. The objective of this investigation was to identify areas to improve and optimize the equipment to ensure continued compliance with OEPA regulations. The investigation included field inspections and testing of the combustion and air pollution control equipment. The first phase of this investigation provided field inspections and recommendations on equipment maintenance. The second phase optimized the system operation through a series of combustion and emission tests.

Equipment Inspections

Inspection included visual inspection of the coal storage and handling system, visual inspection and smoke bomb testing of all mechanical dust collectors, smoke bomb testing of all boiler settings, visual inspection of all boiler stokers and furnace areas, boiler and air pollution control equipment breeching, and the wet scrubber system. Although Boiler No. 4 was in a standby status and required major repair work on the stoker, it was given the same level of inspection to provide a contingency plan in case it ever needed to be placed in operation.

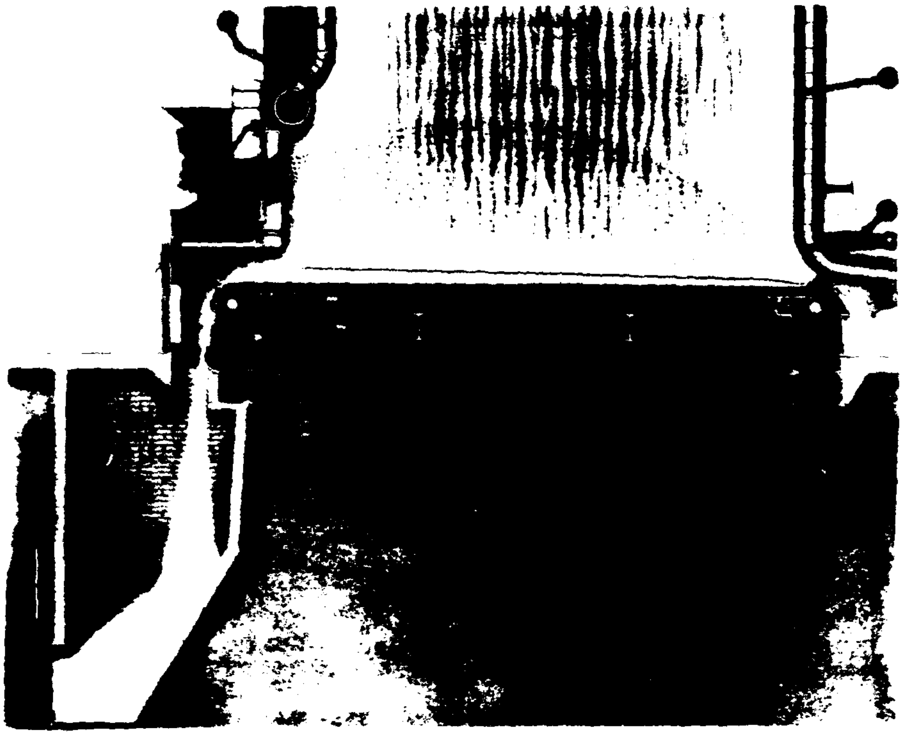
Coal Storage and Handling System

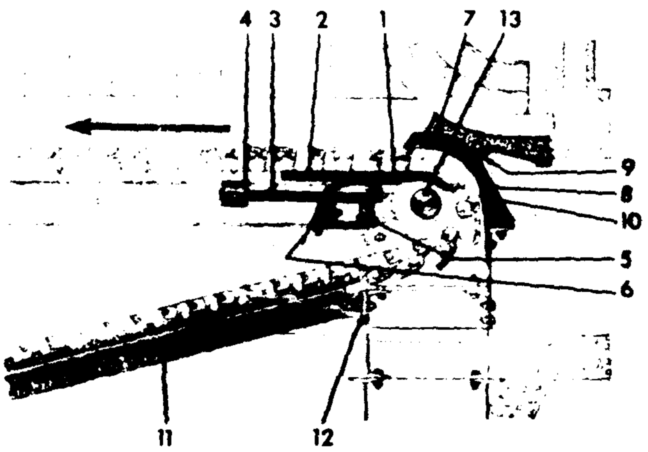
Coal is delivered to the central heating plant by rail cars that are emptied by a mobile crane and clamshell bucket. The crane stacks the coal in a single pile up to 25 ft tall. This is not a good practice for bituminous stoker coal for two reasons. First, piling the coal creates fines by agitation, and segregates the coals. The fines do not burn well in spreader stokers. Segregation occurs because large pieces of coal tend to roll to the outside and lower edges of the pile, creating separate areas of small and big pieces; coal sizes are not equally distributed in the pile. The coal size distribution delivered to the feeder hopper must meet the specifications required by the stoker. (Coal specifications for stokers are more fully discussed in the "Coal Quality" section, p. 52.) Second, large piles tend to spontaneously combust because the coal in the middle of the pile oxidizes, creating heat that cannot dissipate through the thick pile. The heat builds up until the coal begins to burn. During the inspection, smoke was observed coming from the southern edge of the pile.

The coal is transferred to the plant by front-end loader, which dumps into a hopper that feeds a silo outside the plant. The coal is then transferred to a mobile coal weigh larry which weighs the coal before the coal is transferred into the stoker feeder hopper. Boiler No. 8 could also be fed directly by screw conveyor, bypassing the weigh larry. If the coal is not weighed before it enters the stoker, boiler efficiency can not be measured. The coal-handling equipment appeared to be in good working order.

Spreader Stokers

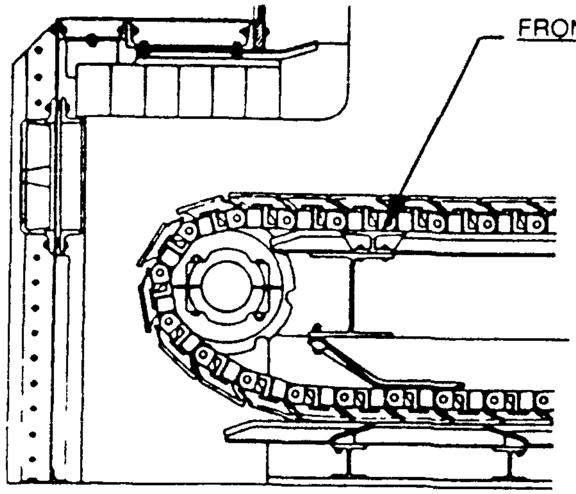
A typical repair item for all four boilers was the rear grate seals. On boiler No.8, a Detroit Stoker, these are called the rear grate seal tuyeres (Figure 7). On boilers Nos. 4, 6, and 7, Riley Stokers, they are called rear grate refractory-filled air seals (Figure 8). These seals prevent air leakage at the rear of the grate surface and, in conjunction with the front and side seals, maintain minimum excess air in the furnace.





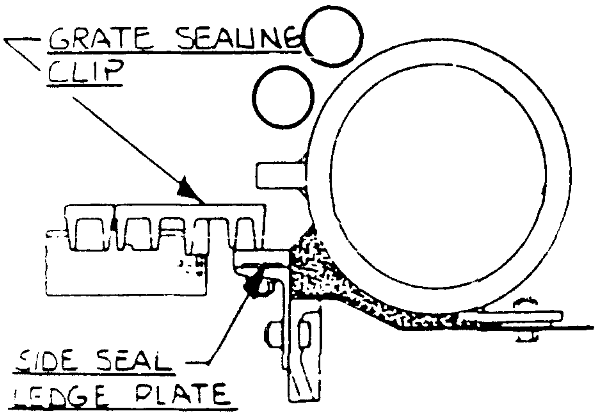
1 Rear coking section (specify width)
2 Rear coking section extension (specify width)
3 Upper air seal weight arm
4 Air seal weight
5 Fulcrum for rear upper air seal weight arm
6 Fulcrum support
7 Rear tuyere
8 Rear tuyere support
9 Angle (or bar) for rear tuyere support casting
10 Rear tuyere support air seal (specify width)
11 Rear slide rail
12 Bracket for rear slide rail
13 Rear grate shaft (specify length)

Figure 7. Detroit stoker rear grate seal and deflector tuyeres.

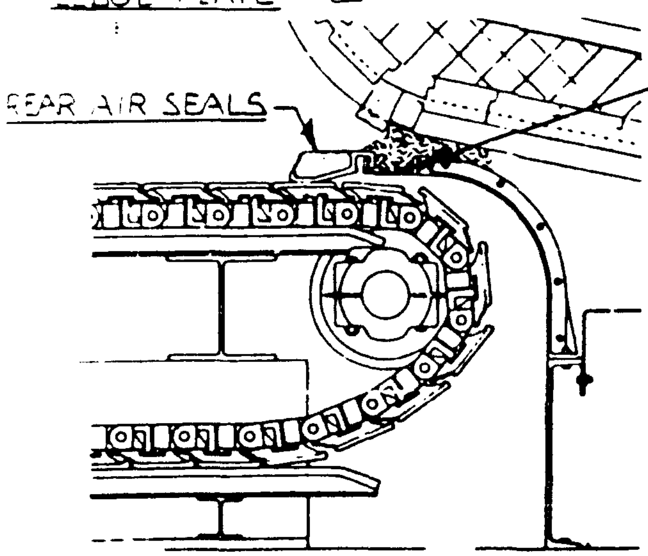


AIR SEALS

Riley Traveling Grate Spreader Stokers are equipped with effective air seals. There are three sections of cast iron air seals at the discharge end of the unit. As shown, the air seals are bolted to cross members of the stoker frame. A positive straight line seal between the traveling grate surface and stoker frame is assured



Heat-resisting grate sealing clips ride on cast iron ledge plate sections at the sides of the stoker. This method of sealing between stoker and furnace provides freedom of expansion and a positive seal at sides of the stoker.



Refractory-filled air seals of cast iron ride on the grate surface. They are secured by seal supports attached to cast iron rear panel sections. Opening caused by expansion and contraction of rear furnace wall tubes is effectively sealed by packed mineral wool insulation.

Figure 8. Riley stoker grate seals.

The feeder plates and blades (Figure 9) need to be replaced on boiler No. 8. Boiler No. 4 needed the most repairs, requiring repair to the skid shoes, drive shaft and idler shaft bearings, drive shaft sprockets (Figure 10), feeder arms (Figure 11) and deflector tuyeres (Figure 7). Table 3 summarizes the recommended repairs for each of the stokers.

Fuel feeders must be kept in good operating condition for optimum fuel feed control and uniform spreading of fuel onto the grate surface. This can only be accomplished with proper operation and maintenance, which includes an ample supply of spare parts and lubricants at all times.

The stoker and auxiliary equipment should be given a complete general inspection at least once a year. This should include inspection of the entire grate surface, to identify worn skid shoes and rails, burned grate clips, bent grate racks, worn chain links, grooved side seal ledge plates, and worn grate sealing clips. Drive shaft and idler shaft bearing wear should also be noted, along with condition of the sprockets. These sprockets can be reversed, if necessary, in order to obtain a new wearing surface.

If maintained and operated properly, spreader stokers are reliable under both steady and variable load conditions and respond well to load changes while maintaining uniform steam pressure and flue gas conditions conducive to efficient emission control equipment operation.

Boiler Multicyclone Dust Collectors

Each boiler has a multicyclone fly ash or dust collector similar to the one shown in Figure 12. Under optimum operating conditions, these collectors can remove about 95 percent of the fly ash particle greater than 10 microns in diameter. The collection efficiency is highly dependent upon the vertical vortex created by the centrifugal motion of the dirty gas as it enters the collecting tube through the inlet vanes (Figure 13). As the inside surface of the collecting tube erodes and a hole is allowed to develop, the vertical vortex is destroyed and collector efficiency is greatly reduced.

Efficiency of the collector is also reduced if outside air is allowed to leak into the hopper area where static pressures are normally around -7.3 inches of water. Efficiency is reduced by the re-entrainment of fly ash particles into the clean gas flow created by the flow of outside air into the hopper. The same re-entrainment action will also occur if dirty gas is allowed to flow from the dirty gas inlet of the collector into the hopper area through broken seal welds on the dirty gas tube sheet.

The boiler collectors were visually inspected and smoke bombed to identify air infiltration sites. Several leaks were noted along with several areas of severe corrosion at the dirty gas inlet breeching.

The corroded areas of the dirty gas inlet breeching walls of Boilers No. 7, 6, and 4 were other sources of air infiltration into the flue gas flow. A typical breeching arrangement for Boilers No. 7, 6, and 4 is shown in Figure 14, with the corroded areas noted. Corrosion most likely occurred during light heating loads and during the winter heating season where the outside air that is supplied to the forced draft fan cools the surrounding duct to the dew point temperature. Although the flue gas directly in contact with the duct is below the dew point, the average flue gas temperature to the mechanical dust collector inlet was probably above the dew point temperature, since there were no signs of plugged inlet ramps.

Figure 15 shows a typical collector tube configuration with a socket joint detail. The sketch shows that, if the socket joint is not sealed, dirty gas will flow through the joint and on to the clean gas flow, resulting in a lower dust collection efficiency. Table 4 summarizes the recommended repairs on the boiler multicyclone collectors.

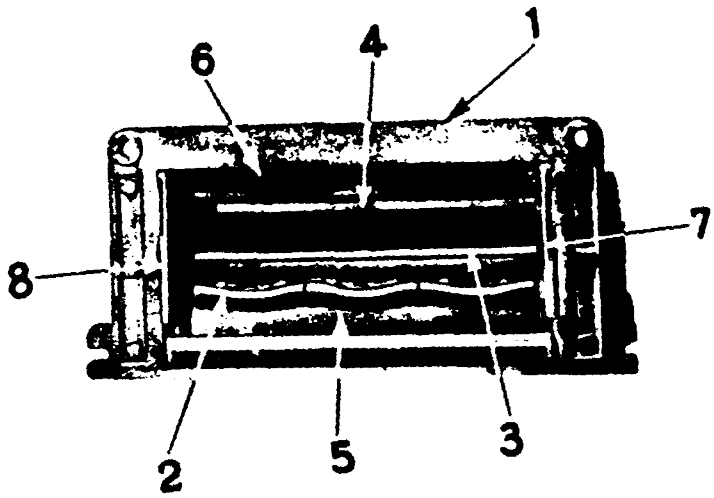


Figure 28—Standard coal feeder assembly (view taken from rear)

Parts shown in Figure 28

1. Feeder base plate
2. Blades for rotor
3. Spilling plate
4. Feed plate
5. Rotor drum
6. Rear cross plate
7. Baffle plate, L.H.
8. Baffle plate, R.H.

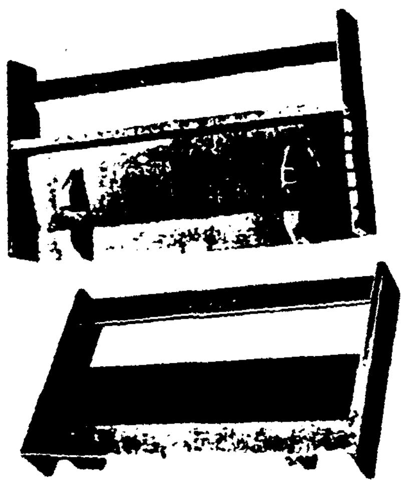


Figure 29—Feed plate

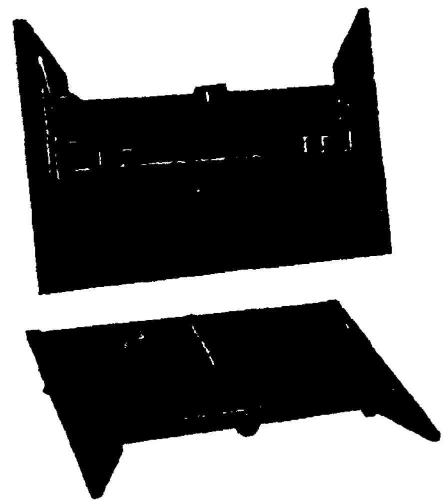


Figure 30—Spilling plate

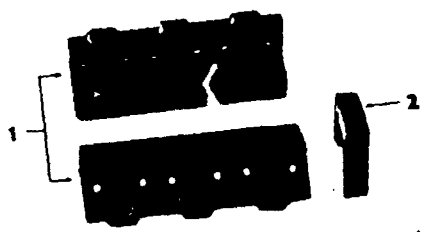


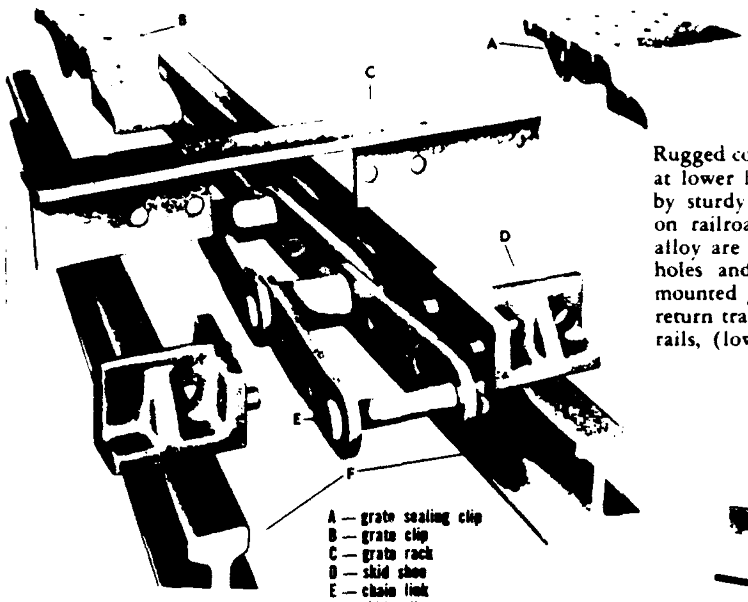
Figure 31—Wear plate for feeder base plate

Parts shown in Figure 31

1. Wear plate for feeder base plate (views from top and bottom of plate)
2. Wear plate filler

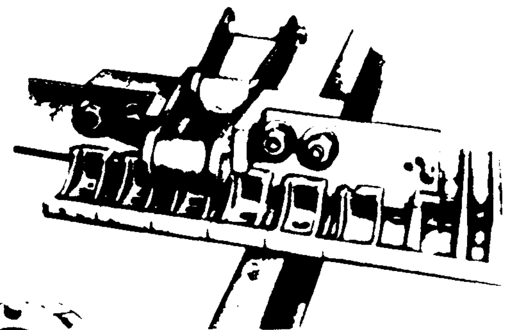
Figure 32—Deflector tuyere (blank) and deflector tuyere filler (located at top rear of feeder)

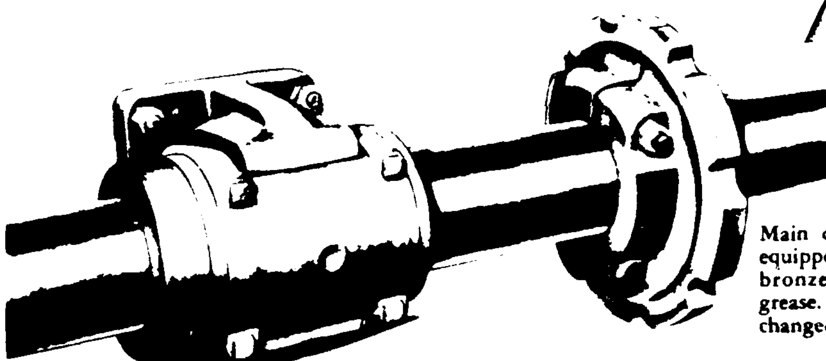
Figure 9. Detroit stoker feeder assembly.



GRATE SURFACE DETAIL

Rugged construction features of the grate surface are shown at lower left. In active position, the grate surface secured by sturdy skid shoes and heat treated steel chain, slides on railroad type skid rails. Grate clips of heat-resisting alloy are two inches wide with a pitch of six inches. Pin holes and slots provide uniform air distribution. Slip-mounted grate clips are easy to install and service. On its return travel to the furnace the grate surface rides on skid rails, (lower right).

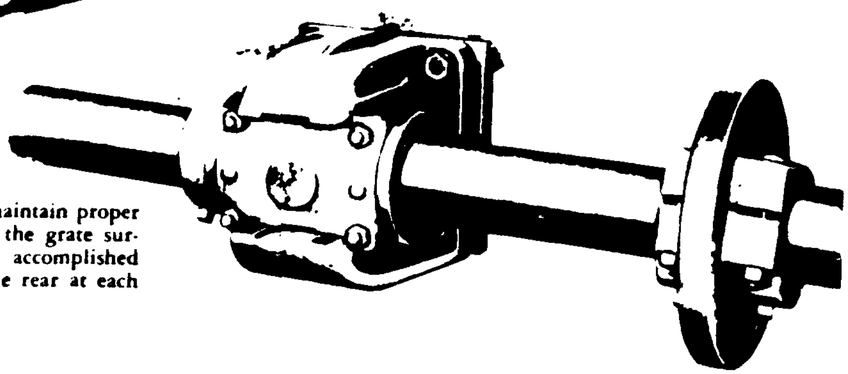




DRIVE SHAFT

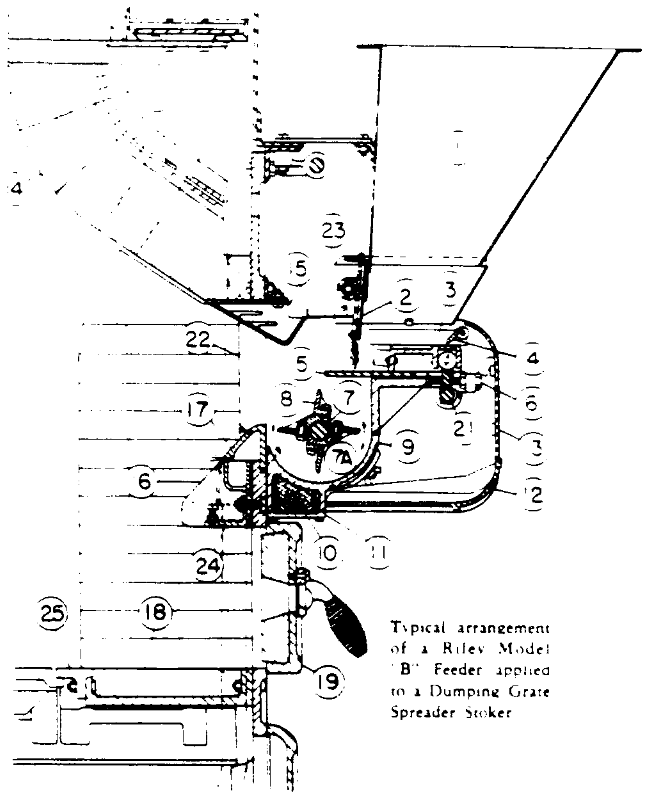
Main drive and idler bearings are equipped with split-type graphited bronze bushings and require no grease. Bushing halves can be interchanged for additional long life.

IDLER SHAFT

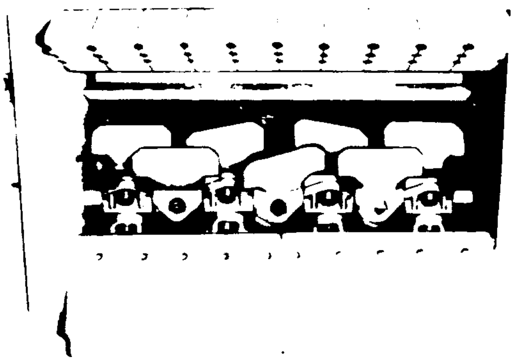


Adjustable idler bearings maintain proper tension and adjustment of the grate surface. Adjustment is easily accomplished by jackscrews located at the rear at each bearing.

Figure 10. Riley stoker grate assembly.

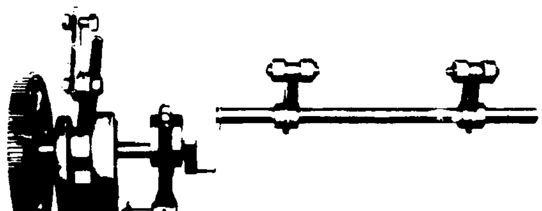


Typical arrangement of a Riley Model "B" Feeder applied to a Dumping Grate Spreader Stoker

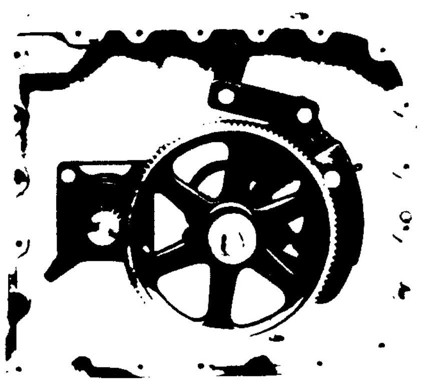


Adjustable Distributor Blades

Accurate distribution of coal is obtained by setting the speed of the distributor and positioning the angularity of the distributor blades. Uniform lateral and longitudinal distribution of fuel can be attained over the complete load range.



Feeder drive mechanism complete with rocker shaft assembly



Feeder Drive Mechanism

The feeder drive mechanism of the Riley Model "B" Spreader Stoker Feeder is unique in its simple design and construction. The drive employs the Stephenson Link principle which is controlled by adjustment of the feeder control to regulate the desired feed rate. Levers, eccentric, gears and their bearings are totally enclosed in a sturdy housing. Splash lubrication of this mechanism minimizes wear and maintenance to assure uninterrupted operation.

Figure 11. Riley stoker feeder assembly.

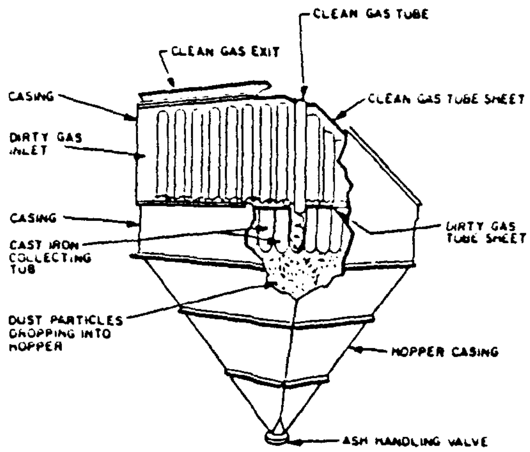


Figure 12. Multicyclone collector schematic.

Table 3

Stoker Maintenance Recommendations

Boiler No. 8 - Detroit Spreader Stoker	** Replace eight rear grate seal tuyeres ** Replace all feeder blades on Feeders Nos. 1 and 2 (left to right facing boiler front) ** Replace all feeder plates and spilling plates
Boiler No. 7 - Riley Spreader Stoker	** Replace worn rear grate refractory
Boiler No. 6 - Riley Spreader Stoker	** Replace refractory on rear grate air seals
Boiler No. 4 - Riley Spreader Stoker	* All refractory filled air seals including support channels need to be replaced * Approximately 70% of skid shoes need replacement. * Replace front air seals cut by worn skid shoes. * Replace drive shaft and idler shaft bearings * Drive shaft sprockets should be reversed to obtain new bearing surface, or replaced * Two feeders need new arm pins and rollers for a correct pusher box stroke * Replace deflector tuyeres on all three feeders
	** Repaired prior to testing

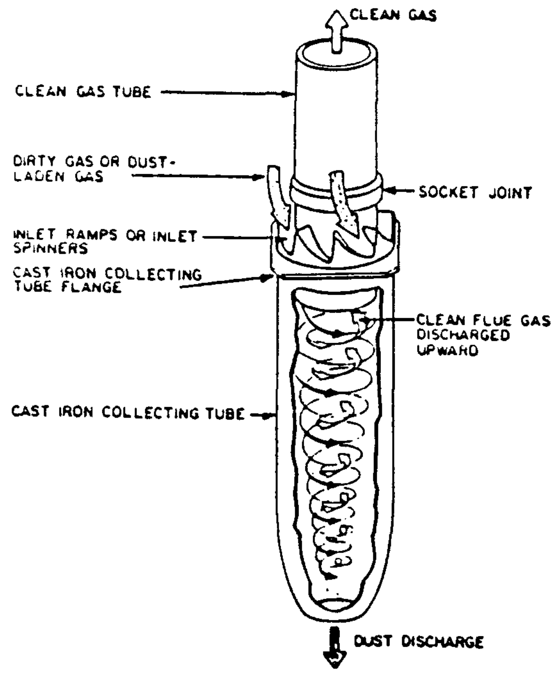


Figure 13. Multicyclone collector tube schematic.

Boiler Settings

Internal inspections and smoke bomb testing showed extensive casing leakage for Boiler No. 4 and a considerable amount of casing leakage for Boilers No. 8, 7, and 6. Leaking air into the boiler setting due to poor condition of refractory, brick, insulation and casing will increase the flue gas flow and result in a lower boiler combustion efficiency. Apart from lowering efficiency, a high percentage of excess combustion air may overload the mechanical dust collector with higher volumes of flue gas.

At high steam loads, this will result in pressure drops across the mechanical dust collectors that exceed the optimum design range. This will tend to break up the fly ash particles and possibly create submicron emission particles that will flow through both the boiler multicyclone collector and the common multicyclone collector. This leaves the BAHCO scrubber system with the task of collecting the particles, which is not its main purpose. Most of the leaks identified were sealed with high temperature caulk and castible refractory prior to combustion and emission test.

Common Flue Gas Breeching

The common flue gas breeching connects the flow from all four boilers and directs the flow through the common multicyclone collector and scrubber. The common breeching also contains a makeup air

stack to provide additional air to optimize scrubber operation. The combination of the cold makeup air, infiltration from offline boilers, and high sulfur coal had caused the flue gas to drop below the acid dew point throughout the duct. This caused severe corrosion in the common duct, leaving holes in the duct work, which caused more air infiltration. The following repairs are recommended (to be done before testing) to alleviate the infiltration problems:

1. Seal off the open end of the breeching duct to eliminate uncontrolled air infiltration into flue gas flow.

2. Repair controls for the common breeching damper for regulation of desired air infiltration.

3. Patch areas of the common breeching, especially the common dust collector inlet expansion joint.

It was necessary to minimize the amount of air infiltration into the flue gas going to the common mechanical dust collector and on to the scrubber system to avoid an acid dew point condition at the collector inlet during upcoming stack testing in February. It was believed that the load demand in February would be sufficient to produce the required gas flow through the scrubber system with only minor regulation of outside air through the damper. The flue gas inlet temperature to the mechanical dust collector must be kept above the acid dew point temperature to maintain mechanical collector efficiency, or certain operational problems occur.

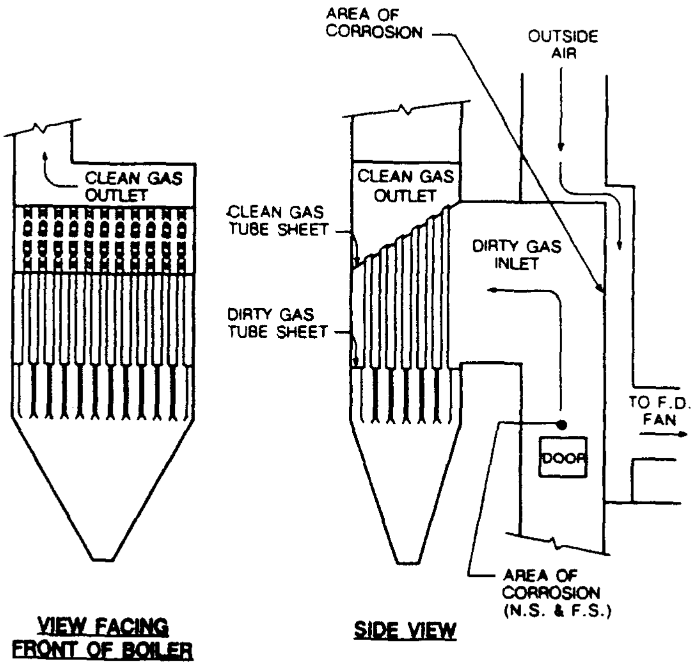


Figure 14. Rickenbacker ANGB multicyclone collector schematic.

When all or a portion of the flue gas drops below the sulfur trioxide dew point temperature, the inlet vane, ramp, or spinner of the cast iron collecting tubes (Figure 15) gets wetted by the weak solution of sulfuric acid, and fly ash particles stick in this wetted solution. When the flue gas temperature is increased above the sulfur trioxide dew point temperature, the water is evaporated out of the wetted solution and a thin layer of hard (concrete-like) material remains on the inlet vanes, ramps, or spinners. Repeated cycling above and beyond this dew point temperature causes the layer of hard material to build until the flow pattern and quantity of flow through the individual tube is reduced.

The thin layer of hard material is very rough in texture because only large fly ash particles stick to the wetted surface. This rough-textured surface causes uneven centrifugal forces and flow into the cast iron collecting tube, which disrupts the dirty-flue-gas/clean-flue-gas vortex. When the vortexes are disrupted, re-entrainment of the fine fly ash particles occurs, greatly decreasing the efficiency of the mechanical dust collector.

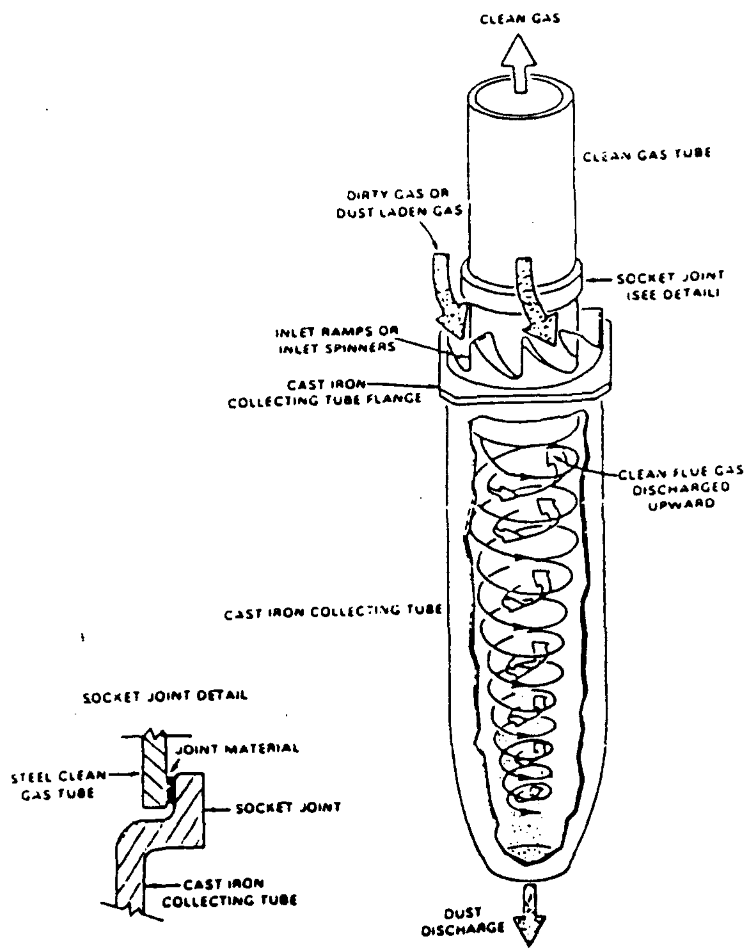


Figure 15. Collector tube and socket joint schematic.

Table 4

Boiler Multicyclone Collector Maintenance Recommendations

Boiler	Recommendation
4	** Repair corrosion holes in dirty gas inlet breeching walls Repair 1 socket joint leak Repair dirty gas tube sheet leakage
6	** Repair corrosion holes in dirty gas inlet breeching walls ** Repair 7 socket joint leaks
7	** Repair corrosion holes in dirty gas inlet breeching walls ** Replace 4 cast iron collecting tubes
8	** Repair 8 socket joint leaks
	** Repaired prior to testing

All tubes will not have the same thickness of hard material buildup on inlet vanes, ramps or spinners. The amount of buildup depends on: (1) temperature variation in the dirty gas inlet, and (2) distribution of particle size within the collector.

When the thin layers of hard materials build up to such a thickness that the cross-sectional inlet area of the inlet vane, ramp, or spinner is reduced, then the quantity of flue gas flow to these tubes is reduced. When there is uneven flow to some of the tubes through the inlet vane, ramp, or spinner, then the complete flow pattern in the entire collector changes.

The thin layers of hard material also build up in the clean gas tube but, because of its large cross-sectional area, the hard material does not reduce its flow in proportion to the inlet vane, ramp, or spinner. This uneven flow then causes some flue gas to enter the tubes with less thick layers of hard material at the inlet vanes, flow down into the hopper area, across the hopper, re-entraining particulate in the flow and exiting the clean gas tube of those tubes with thick layers of hard material at inlet vanes (Figure 16). The reason the flue gas flow will exit the clean gas tubes with thick material at the inlet vanes is because the induced draft fan has the same suction of negative static pressure on all clean gas tubes.

A dew point temperature of approximately 300 °F was estimated using ultimate analysis of the coal burned during our stack tests and an average recorded boiler outlet O_2 of 11 percent. It is conceivable that the common mechanical dust collector had been operated at below the dew point temperature for prolonged periods of time. The flue gas inlet temperature data taken while stack testing shows that a maximum temperature of 309 °F was recorded during emission testing at maximum heating load conditions. Temperature data recorded during stack testing at normal heating load conditions was as low as 207 °F.

Common Multicyclone Dust Collector

The common multicyclone collector is similar to the individual boiler collectors, only larger with more tubes. The observed plugging of 20 to 30 percent of the inlet ramps with fly ash during power washing was further evidence of an acid dew point condition, resulting in lower dust collection efficiency. Several socket joint leaks were identified during the smoke bomb test. However, because most of the

tubes were badly worn by erosion, all the tubes were replaced and resealed. The collector hopper and dirty gas tube sheet also required seal welding to eliminate air infiltration (Figures 17 and 18). Maintenance recommendations for the common multicyclone collectors (repaired prior to testing) were:

1. Power wash the collector inlet and outlet areas prior to inspection and leak testing.

2. Sixty-two cast iron collecting tubes were badly worn from fly ash erosion, 16 of them having holes. All 108 tubes should be replaced.

3. Seal the weld collector hopper and dirty gas tube sheet.

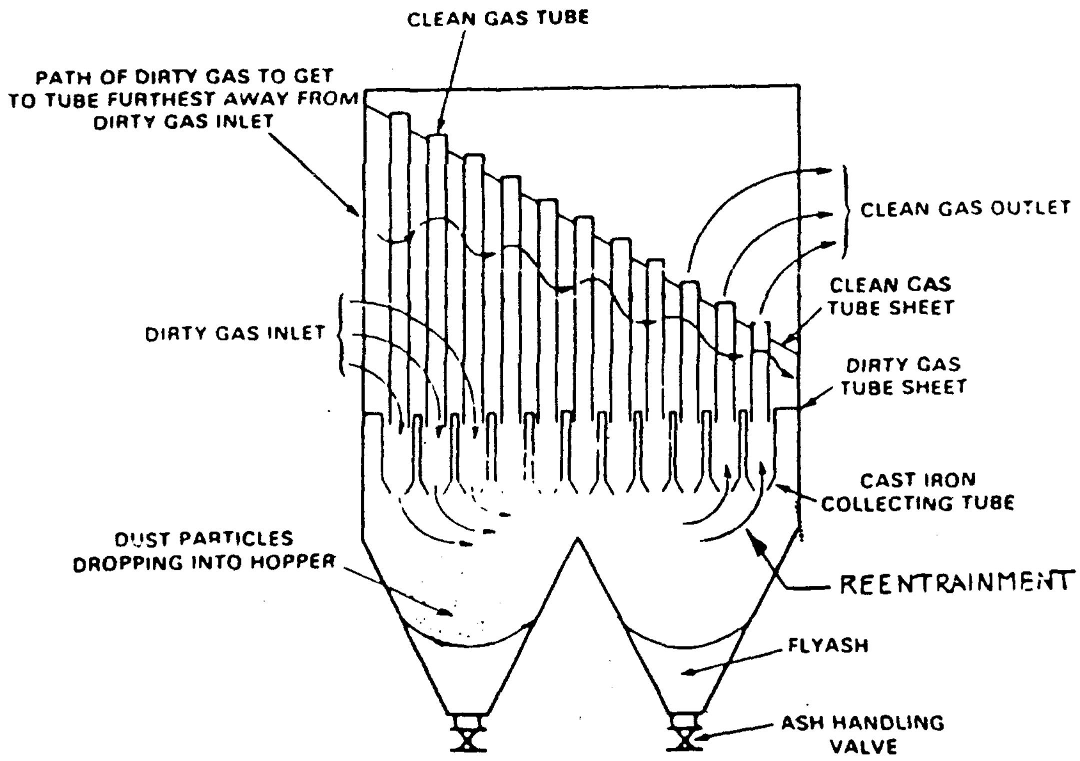


Figure 16. Multicyclone dust re-entrainment.

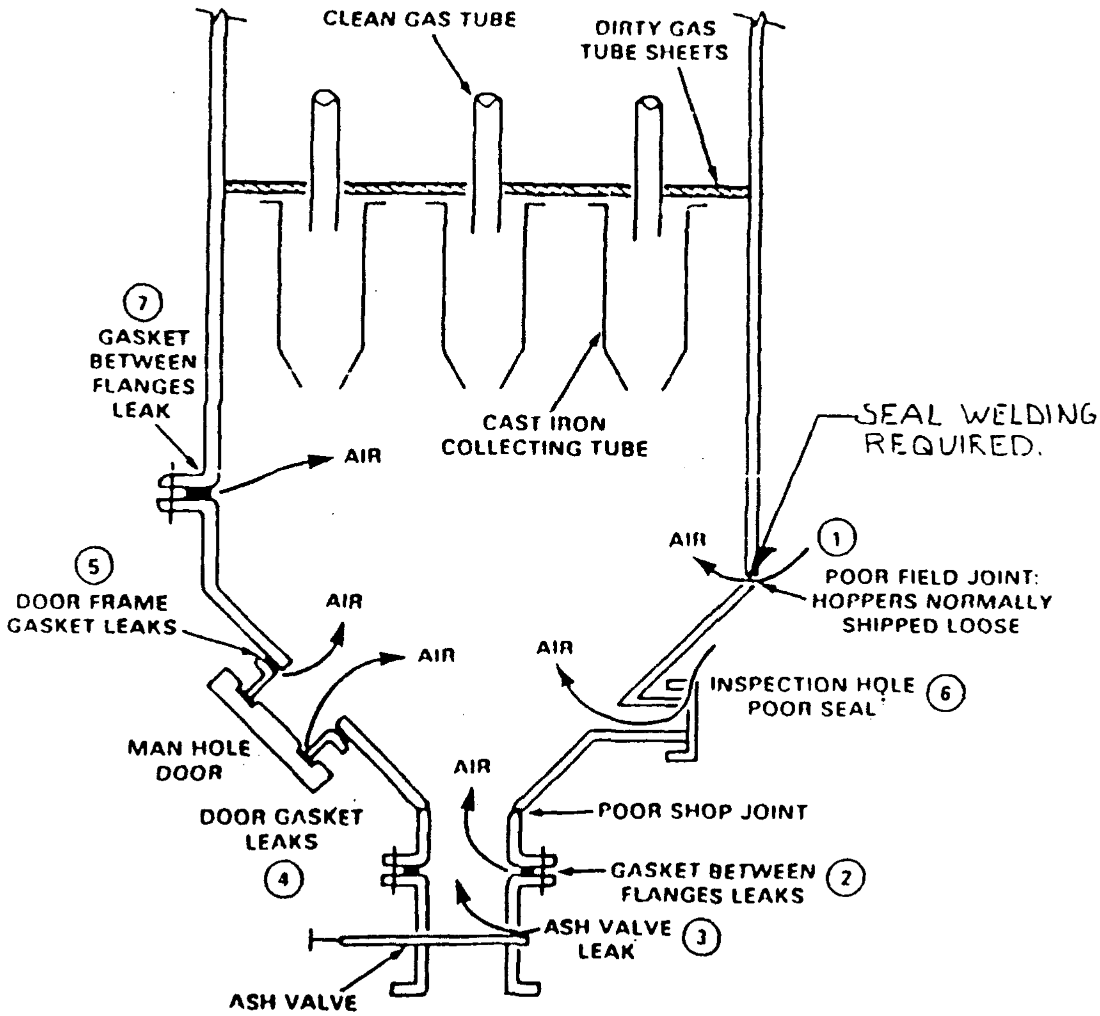


Figure 17. Collector hopper and dirty gas tube sheet seal.

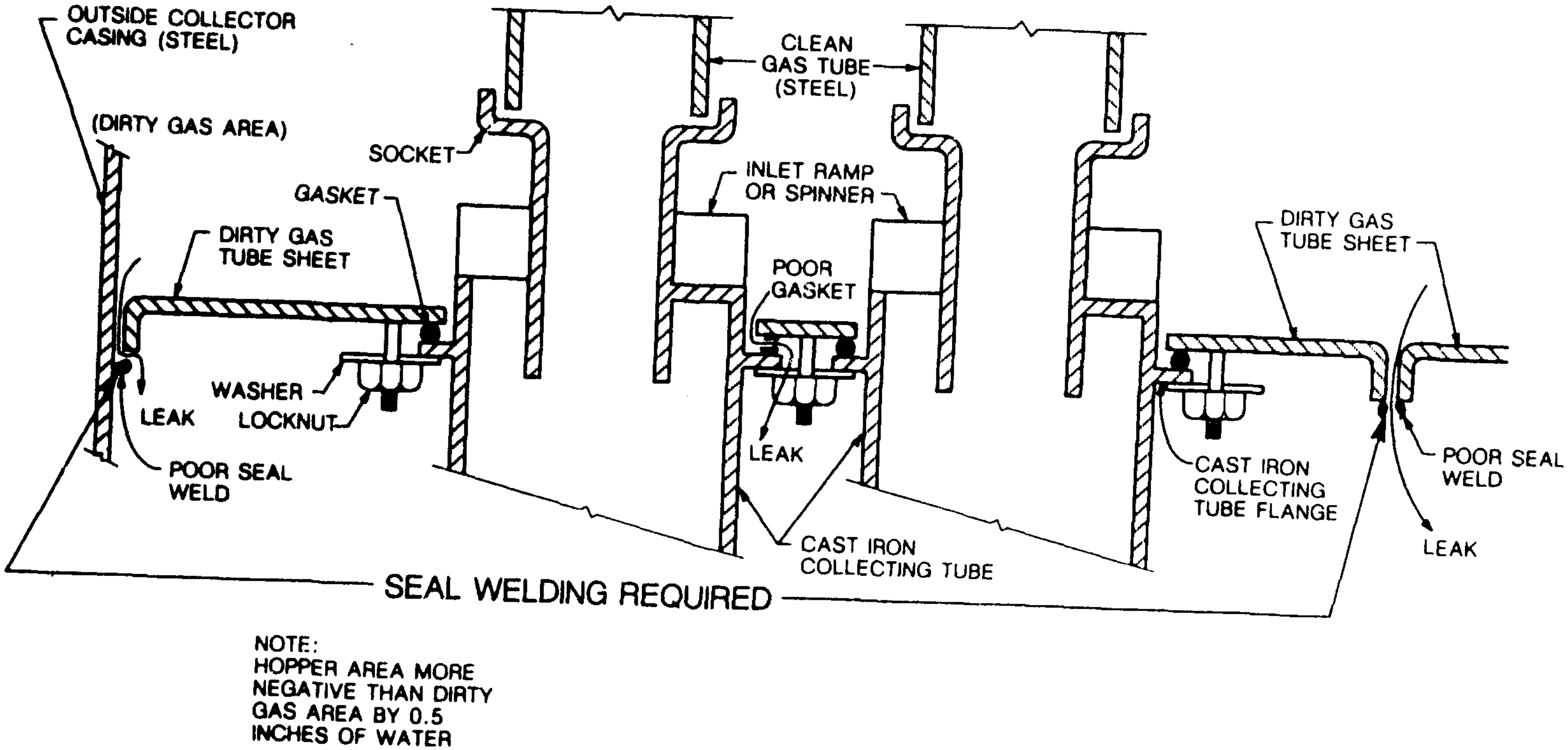


Figure 18. Hopper tube sheet detail.

BAHCO Wet Scrubber

The BAHCO wet scrubber system was installed at Rickenbacker ANGB in 1976 as part of a cooperative research program conducted by the USEPA and the U.S. Air Force. The unit is a highly unusual "stacked" orifice scrubber. It was the first such system installed, and the only one of three units ever built.

Inspection results indicated significant liquor re-entrainment from the scrubber stack. One of the clearest indicators of this condition was the persistent rainout of large droplets which occurred within 40 yds downwind of the scrubber system. The rate of deposition was roughly equivalent to a constant, heavy drizzle. The droplets also hit the scrubber support structure, the lime storage tank, and other equipment in the immediate vicinity.

Photographs shown in Figures 19 and 20 clearly show the stains resulting from the scrubber liquor salts and fly ash that remain as the droplets dry.

Figure 19. Rainout deposits on scrubber shell and adjacent lime silo.

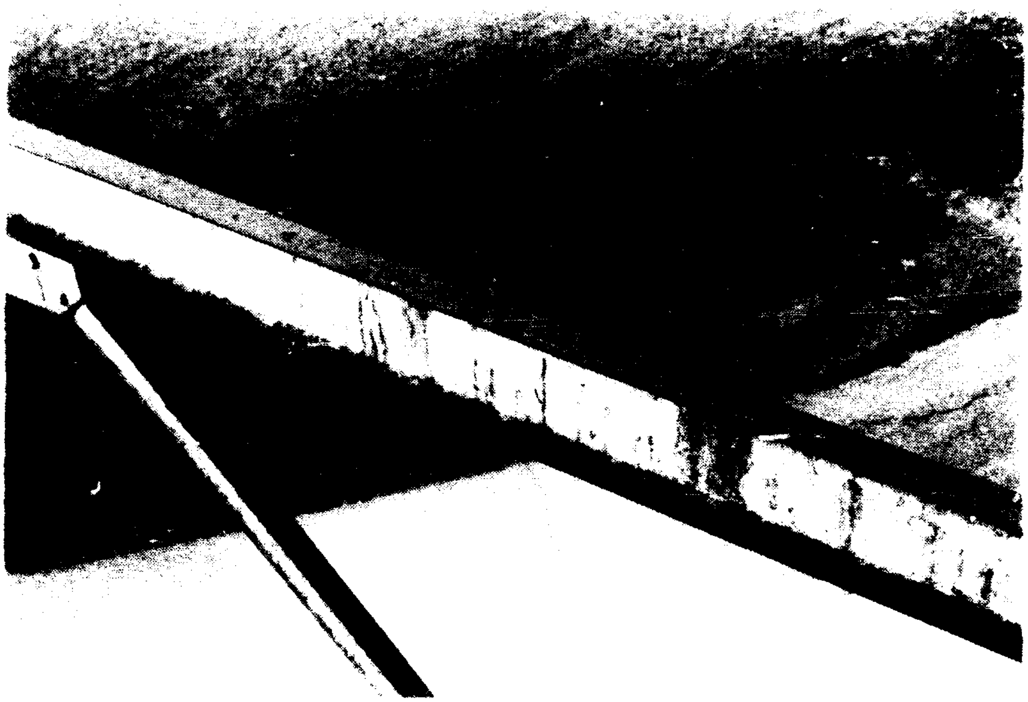


Figure 20. Deposits on beam close to scrubber stack.

The rainout conditions created several problems. During cold weather operation, the freezing liquor created slip hazards on the concrete pad and ladders around the scrubber system. Also, the salt-laden droplets in the stack could have affected particulate emission test results. Based on the observed conditions, the reduction of liquor re-entrainment was considered necessary.

Based on the above inspections, an optimization program was carried out, which consisted of a progression of operational changes and equipment modifications aimed primarily at a chronic liquor re-entrainment condition. The analysis was initiated in February 1987 and concluded in April 1987.

System Testing and Optimization

Preliminary inspection results indicated that the wet scrubber system was subject to re-entrainment problems. This was indicated by the deposition of black scrubber liquor on all heating plant equipment adjacent to the scrubber stack and by the persistent rainout conditions within 50 yd of the scrubber system. Most of the engineering efforts were directed toward this problem. However, it was also presumed that other conditions could contribute to high particulate emissions. For this reason, this analysis included an

evaluation of scrubber pressure drop, gas-liquor maldistribution, and coal-fired boiler performance (as discussed in the previous section).

Program Summary

A logical series of performance changes and equipment changes was made in an attempt to optimize performance. These started with inexpensive operational changes and concluded with several equipment modifications. The major steps were made in the following order:

1. Changes in the stage 1 and stage 2 static pressure drops
2. Cleanout of downcomer from stage 2 drop collector for increased liquor flow rate to stage 2
3. Improved operation of the lime addition circuit
4. Elimination of the mist eliminator baffle plate
5. Elimination of the standing liquor in the stage 2 drop collector
6. Modification of the induced draft fan controller
7. Increased gas flow rate through the scrubber to increase cyclonic action in the demister.

Following the last change, the tested particulate emissions were less than 60 percent of the allowable 0.16 lb/MBtu input. The residual opacity during the compliance tests was also very low.

Optimization Steps

The highly unusual characteristics of the BAHCO wet scrubber system made it necessary to conduct the performance evaluation study using a step-by-step approach based on emission tests. There were no sets of reliable performance standards or operating guides due to the very limited industrial experience with this "stacked" orifice scrubber arrangement. This program began on 23 February 1987. The initial efforts focused on operational changes that could be completed easily and quickly. Later efforts concerned equipment modifications. Some of these were necessary to adjust the system for the much lower heating plant operating rates caused by the closure of portions of the base.

<u>23-25 February 1987 Tests</u>. The initial particulate testing was conducted beginning 23 February 1987 to establish a baseline set of data to evaluate future changes. The pressure drops, liquor flows, and gas flows were arbitrarily set. The total system static pressure drop was set near maximum levels by adjustment of the stage 1 and 2 level tanks. This setting was used since wet scrubber particulate emission is usually (but not always) directly proportional to the static pressure drop. The lime tank return flow to stage 1 was set at approximately 50 percent of maximum capacity, which was close to the levels typically selected by plant personnel. The fan motor current was initially set at 63 amp, although it dropped to 48 amp during the third run due to reduced hot water generator operating rate. The system operating data for the 23 and 25 February tests are shown in Table 5.

These test results clearly indicated that high static pressure across the scrubber vessel did not reduce particulate emissions. In fact, these emissions were probably higher than emissions prior to the tests due to increased re-entrainment conditions. This was caused by the high liquor levels in stages 1 and 2, which were set to reach the high pressure drop conditions. Severe droplet rainout from the stack was observed during these tests.

Table 5

Results of Initial Testing, 23 to 25 February 1987

Date	Run	Gas Flow (ACFM)	Emissions (lb/MBtu)	Fan Current (amp)	Static Press Drop (in. w.c.)
2/23	1	70,192	0.1492	63	22-24
	2	62,126	0.1683	63	22-24
	3	51,326	0.1861	48	22-24
2/25	1	69,606	0.2993	64	24
	2	66,876	0.1669	63	25
	3	61,340	0.3080	62	25

4 March 1987 Tests. The primary purpose of this test series was to evaluate very low static pressure drop operating conditions. The rationale was that this should reduce the contribution of liquor re-entrainment emissions to the total particulate catch being measured. The scrubber pressure drops across stage 1 and stage 2 were set to minimum levels by lowering the liquor levels. This reduced the maximum gas velocities through the orifices and thereby minimized liquor pickup. The total static pressure drops across both scrubber stages were in the range of 7 to 10 in., which is consistent with the operating conditions of other types of scrubbers serving coal-fired boilers. Therefore, there was some optimism that the system would perform adequately under these conditions.

Prior to the test series, the unit was taken offline and thoroughly cleaned by plant personnel. Settled solids in the stage 2 "pan" and stage 1 and 2 drop collectors were removed. Also, the downcomer from the stage 2 level tank and the stage 1 "mill" was cleaned. This line had become more than 50 percent occluded due to occasional scaling problems. Table 6 shows the pertinent data from this test.

Emissions continued to be in excess of the 0.16 lbs/MBtu limit. Liquor re-entrainment was very low as indicated by minimal rainout from the stack and the total absence of a steam plume during run #3. However, there were indications of poor fly ash collection in the scrubber at these very low (and atypical) pressure drops. The plume residual opacity was higher than during the 23 and 25 February tests, and the gas stream was not fully saturated. Also, there was a very clear sulfur dioxide odor in the exhaust gas, which was not present during the early test series and during routine operation.

Based on these tests, it was apparent that the emission problem could not be solved simply by reducing droplet re-entrainment rates or by reducing the solids content of the droplets that are re-entrained. It would be necessary to maintain moderate pressure drops while minimizing liquor re-entrainment by other means. Possible options included:

1. Installation of mesh pad, chevron, or bed-type demisters
2. Changes in the stage 2 level tank and/or stage 2 drop collector
3. Changes in the existing cyclonic demister section.

The initial efforts concerned the stage 2 equipment and the cyclonic demister since the practicality of an add-on demister was seriously questioned.

Table 6

Results of 4 March 1987 Tests

Date	Run	Gas Flow (ACFM)	Emissions (lb/MBtu)	Fan Current (amp)	Static Press Drop (in. w.c.)
3/4	1	65,841	0.232	62	8.9
	2	66,333	0.249	63	7.6
	3	59,622	0.238	58-47	6.2-24.0

17 to 18 March 1987 Tests. Prior to these tests, the large disk immediately below the scrubber stack was removed. Calculations indicated that the gas flow rates around the annular opening ranged from 23.7 to 27.6 ft/min at gas flow rates of 60,000 to 70,000 ACFM. Also, the gas velocities flowing into the stack from the top of the disk ranged from 29.0 to 33.8 ft/min at the same gas flow rates. These velocities could easily create re-entrainment conditions for liquor migrating up the demister side walls or liquor trapped above the deflector plate.

During these tests, care was taken to maintain maximum static pressure drop across stage 1 and minimum static pressure drop across stage 2. In this manner, the re-entrainment problems created in stage 1 could be corrected by droplet collection in stage 2. Furthermore, the liquor level in the stage 2 drop collector was minimized by switching the overflow lines and recycle lines. All of the liquor collected in the stage 2 drop collector flowed immediately into the stage 1 "mill" rather than standing in a pool of water inside the drop collector.

An improper cam in the induced fan inlet damper controller was found and replaced prior to the tests. This control problem had prevented optimum fan operation at the relatively low gas flow rates that existed due to reduced base heating demand. Also, preliminary plume observations indicated that excessive emissions can occur when the fan motor currents are less than 60 amp. This is apparently due to unsteady state surging gas-liquor conditions within one or both of the stages. Table 7 shows the pertinent data from this test.

Despite the equipment modifications, some persistent re-entrainment was seen from the stack. Also, the particulate emission test results showed higher than allowable emission rates.

Cyclonic flow tests were conducted at two elevations within the demister section of the scrubber tower on 17 March. Severe cyclonic flow existed at both locations despite the removal of the 8-ft diameter disk at the top of the demister. Preliminary conversations with two equipment manufacturers, Ceilcote and Munters, confirmed that installation of a mesh pad- or chevron-type demister was not feasible due to the cyclonic flow conditions.

24 March 1987 Tests. Following the tests on 17 to 18 March, it appeared that scrubber liquor re-entrainment conditions could not be corrected. Accordingly, a set of tests was performed on 24 March to determine if the rebuilt mechanical collector would allow for compliance with particulate emission regulations, despite the re-entrainment problems of the scrubber. If so, the scrubber vessel could be redesigned to operate as a simple spray tower scrubber for sulfur dioxide removal. With this configuration, the cyclonic flow conditions and inherent re-entrainment phenomenon could be entirely eliminated.

Table 7

Results of Initial Testing

Date	Run	Gas Flow (ACFM)	Emissions (lb/MBtu)	Fan Current (amp)	Static Press Drop (in. w.c.)
3/18	1	60,596	0.2060	64	24
	2	48,062	0.2210	63	25

Two mechanical collector outlet tests were conducted in the breeching after the induced draft fan and immediately upstream of the scrubber. The gas flow rates were increased by the introduction of dilution air upstream of the mechanical collector to achieve the design static pressure drop levels. The results shown in Table 8 indicated that the fly ash emissions were well above the desired emission rate of 0.16 lb/MBtu. This demonstrated that the scrubber vessel had to retain some particulate removal capability, and that it would not be possible to redesign the scrubber.

During runs 1 and 2, it was noticed that the liquor re-entrainment conditions were substantially reduced, presumably due to both the equipment modifications completed a week earlier and the higher than normal gas flow rates. The latter optimized the effectiveness of the cyclonic action in the modified demister. Accordingly, one additional test was run at the scrubber outlet to document the prevailing particulate emission rates. As indicated in Table 8, results of this test were slightly below the regulatory limit.

Based on this test, a revised system operating procedure was developed to minimize re-entrainment. This involved use of high gas flow rates equal to or above those used in run #3 of the 24 March test. Note that these flow rates were closer to the original design flow rates used before the heating plant was derated due to partial closure of the Base.

31 March to 1 April 1987 Tests. An official OEPA compliance test for particulate emissions was performed on 31 March 1987 and 1 April 1987. The test consisted of two parts: (1) a test at maximum load, and (2) a test at normal load. The second test was requested by OEPA for information on the scrubber turndown and emissions at normal load conditions. The first test, at maximum heating load, provided the basis for the issuance of Rickenbacker's "Permit to Operate."

Maximum boiler loads for Units 6 and 7 were maintained during the 31 March tests. Minimum loads were maintained during the 1 April tests. In both sets of tests, gas flow rates were maintained at relatively high levels, as indicated by the fan currents. The scrubber static pressure drops were maintained from 17 to 22 in. of water range. Also, the stage 2 level was kept at relatively low levels to minimize re-entrainment in this portion of the scrubber.

The results indicated that the scrubber system emissions were well below the regulatory limit of 0.16 lb/MBtu input. Also, the residual plume opacity was very low and well in compliance with the 20 percent opacity limit. Table 9 shows the pertinent data from this test.

Table 8

Results of 24 March 1987 Tests

Date	Run	Gas Flow (ACFM)	Emissions (lb/MBtu)	Fan Current (amp)	Static Press Drop (in. w.c.)
3/24	1	61,322	0.4016	70	N.A.
	2	69,609	0.4048	71	N.A.
	3	66,188	0.1562	70	22.2

Table 9

Results of 31 March to 1 April 1987 Tests

Date	Run	Gas Flow (ACFM	Emissions (lb/MBtu)	Fan Current (amp)	Static Press Drop (in. w.c.)
3/31	1	70,305	0.0620	75	22.6
	2	74,801	0.1234	73	22.5
	3	71,946	0.1164	75	22.5
4/1	1	72,796	0.0888	77	17.5
	2	72,506	0.0700	76	17.9
	3	70,108	0.1545	75	18.3

Alternate Emission Calculations

The emissions shown in tables 5 to 9 were calculated based on the coal F-Factor method. However, the problems typical of coal-fired boilers and the past emission tests at Rickenbacker indicated that several methods should be used to cross check emission rates: (1) standard F-Factor, (2) coal F-Factor, (3) coal input, (4) Btu integrator, (5) Btu indicator, (6) ASME PTC 4.1, and (7) water meter.

A comparison of the two official compliance tests results is given in Tables 10 through 17. Table 10 shows the particulates emission results for the maximum loading tests. Tables 11 through 13 show the measured or estimated heat output, % generator load, fuel input, and heat input for each calculation method. The isokinetic percentages were 92.7, 90.6, and 90.1, respectively. The average boiler outlet O_2 percentages were 10.7, 10.6, and 11.4, respectively. The corresponding stack O_2 percentages were 15.1, 16.3, and 15.2, respectively.

Similarly, Table 14 shows the particulates emission results for the normal loading tests. Tables 15 through 17 show the measured or estimated heat output, % generator load, fuel input, and heat input for each calculation method. The isokinetic percentages were 97.6, 95.4, and 95.8, respectively. The average boiler outlet O_2 percentages were 10.4, 9.8, and 9.6, respectively. The corresponding stack O_2 percentages were 16.7, 17.0, and 16.8, respectively. (Note that only boilers No. 6 and 8 were in operation for the normal load tests.)

The Btu integrator and indicator were not working properly, so they did not provide an accurate estimation of heat output and subsequently are not accurate for calculating the emission rates.

The OEPA allowable emission limit for particulates was based on an average boiler efficiency of 76 percent (as measured during these tests) and the combined rated heat output of the generators (120 MBtu/hr). This gave a maximum heat input of 158 MBtu/hr. Figure 6 (Chapter 3) shows that this resulted in an allowable emission limit of 0.174 lb/MBtu.

The coal input, American Society of Mechanical Engineers Power Test Code (ASME PTC) 4.1, and water meter methods of determining the heat input for calculating the particulate emissions are all very close. This indicates that the coal weigh larry weight measurements were quite accurate. This accuracy was obtained by not using the auger feed system on boiler No. 8 and instead using the coal weigh larry normally used only for the other boilers. The test was also started and stopped with the coal hoppers "topped off," to avoid problems with measuring partially filled hoppers. The F-Factor methods produced somewhat higher emission rates, as expected, but are still well within the OEPA allowable emission limit of 0.174 lb/MBtu.

The modifications to plant operating and maintenance procedures, and to high-quality test procedures provided Rickenbacker a significant margin of safety with respect to air pollution compliance. The particulate emissions from the scrubber could increase 60 percent and still be within OEPA compliance limits.

Table 10

Maximum Load Particulate Emission Test Results

Based On	In Units	Run No. 1	Run No. 2	Run No. 3	Average
Stack	#/Hr	5.96	10.21	11.45	9.207
Standard F-Factor	#/MMBtu	0.0619	0.1240	0.1169	0.1009
Coal F-Factor	#/MMBtu	0.0620	0.1234	0.1164	0.1006
Coal weigh larry	#/MMBtu	0.0592	0.1065	0.1177	0.0945
% Generator load	%	64.07%	61.26%	61.08%	62.14%
*Btu integrator	#/MMBtu	0.1161	0.2125	0.2376	0.1887
% Generator load	%	32.03%	30.20%	29.58%	30.60%
*Btu indicator	#MMBtu	0.1083	0.1960	0.2340	0.1794
% Generator load	%	35.06%	33.23%	30.83%	33.04%
ASME PTC 4.1	#MMBtu	0.0502	0.0863	0.1010	0.0792
% Generator load	%	75.95%	76.04%	71.64%	74.54%
Water meter	#MMBtu	0.0499	0.0859	0.1003	0.0787
% Generator load	%	75.95%	76.04%	71.64%	74.54%
During run - blew soot		NO	YES	NO	
During run - pulled bottom ash		NO	NO	YES	
During run - pulled fly ash		NO	NO	NO	

*NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 11

Maximum Load Run 1

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000	30,000,000	60,000,000	120,000,000
Coal weigh larry				
Heat output	19,952,615	22,000,424	34,929,486	76,882,525
% Generator load	66.51%	73.33%	58.22%	64.07%
Coal input	2,345	2,592	3,928	8,865
Heat input	26,613,405	29,416,608	44,578,872	100,608,885
* Btu integrator				
Heat output	15,890,000	22,120,000	420,000	38,430,000
% Generator load	52.97%	73.73%	0.70%	32.03%
Coal input	1,868	2,607	47	4,522
Heat input	21,199,932	29,586,843	533,403	51,320,178
* Btu indicator				
Heat output	14,240,000	8,036,000	19,800,000	42,076,000
% Generator load	42.47%	26.79%	33.00%	35.06%
Coal input	1,674	947	2,227	4,848
Heat input	18,998,226	10,747,503	25,274,223	55,019,952
ASME PTC 4.1				
Heat output	24,343,400	26,909,900	39,888,000	91,141,300
% Generator load	81.14%	89.70%	66.48%	75.95%
Coal input	2,844	3,152	4,467	10,463
Heat input	32,276,556	35,772,048	50,695,983	118,744,587
Water meter				
Heat output	24,343,400	26,909,900	39,888,000	91,141,300
% Generator load	81.14%	89.70%	66.48%	75.95%
Coal input	2,861	3,171	4,486	10,518
Heat input	32,469,489	35,987,679	50,911,614	119,368,782

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 12

Maximum Load Run 2

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000	30,000,000	60,000,000	120,000,000
Coal weigh larry				
Heat output	20,473,143	22,117,910	30,921,061	73,512,114
% Generator load	68.24%	73.73%	51.54%	61.26%
Coal input	2,420	2,550	3,462	8,432
Heat input	27,517,820	28,996,050	39,366,402	95,880,272
* Btu integrator				
Heat output	16,310,000	19,810,000	120,000	36,240,000
% Generator load	54.37%	66.03%	0.20%	30.20%
Coal input	1,928	2,284	13	4,522
Heat input	21,923,288	25,971,364	147,823	48,042,475
* Btu indicator				
Heat output	15,400,000	5,880,000	18,600,000	39,880,000
% Generator load	51.33%	19.60%	31.00%	33.23%
Coal input	1,820	678	2,083	4,581
Heat input	20,695,220	7,709,538	23,685,793	52,090,551
ASME PTC 4.1				
Heat output	24,343,400	26,818,680	40,087,440	91,249,520
% Generator load	81.14%	89.40%	66.81%	76.04%
Coal input	2,858	3,075	4,469	10,402
Heat input	32,498,318	34,965,825	50,816,999	118,281,142
Water meter				
Heat output	24,343,400	26,818,680	40,087,440	91,249,520
% Generator load	81.14%	89.40%	66.81%	76.04%
Coal input	2,877	3,092	4,488	10,457
Heat input	32,714,367	35,159,132	51,033,048	118,906,547

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 13

Maximum Load Run 3

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000	30,000,000	60,000,000	120,000,000
Coal weigh larry				
Heat output	20,678,640	21,724,398	30,888,729	73,291,767
% Generator load	68.93%	72.41%	51.48%	61.08
Coal input	2,470	2,609	3,502	8,581
Heat input	28,012,270	29,588,669	39,716,182	97,317,121
* Btu integrator				
Heat output	16,730,000	18,410,000	360,000	35,500,000
% Generator load	55.77%	61.37%	0.60%	29.58%
Coal input	1,998	2,211	41	4,250
Heat input	22,659,318	25,074,951	464,981	48,199,250
* Btu indicator				
Heat output	15,000,000	4,480,000	17,520,000	37,000,000
% Generator load	50.00%	14.93%	29.20%	30.83%
Coal input	1,791	538	1,986	4,315
Heat input	20,311,731	6,101,458	22,523,226	48,936,415
ASME PTC 4.1				
Heat output	25,075,000	24,402,000	36,491,000	85,968,000
% Generator load	83.58%	81.34%	60.82%	71.64%
Coal input	2,974	2,909	4,117	10,000
Heat input	33,728,134	32,990,969	46,690,897	113,410,000
Water meter				
Heat output	25,075,000	24,402,000	36,491,000	85,968,000
% Generator load	83.58%	81.34%	60.82%	71.64%
Coal input	2,995	2,930	4,137	10,062
Heat input	33,966,295	33,229,130	46,917,717	114,113,142

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 14

Normal Load Particulate Emission Test

Based On	In Units	Run No. 1	Run No. 2	Run No. 3	Average
Stack	#/Hr	6.81	4.94	11.19	7.647
Standard F-Factor	#/MMBtu	0.0890	0.0694	0.1550	0.1045
Coal F-Factor	#/MMBtu	0.0888	0.0700	0.1545	0.1044
Coal weigh larry	#/MMBtu	0.0917	0.0738	0.1582	0.1079
% Generator load	%	64.34%	59.67%	61.88%	61.96%
*Btu integrator	#/MMBtu	0.2800	0.1946	0.4185	0.2977
% Generator load	%	20.62%	21.71%	22.97%	21.77%
*Btu indicator	#MMBtu	0.1427	0.1018	0.2281	0.1575
% Generator load	%	41.20%	42.18%	42.80%	42.06%
ASME PTC 4.1	#MMBtu	0.0812	0.0599	0.1322	0.0911
% Generator load	%	72.89%	72.04%	74.26%	73.06%
Water meter	#MMBtu	0.0807	0.0597	0.1316	0.0907
% Generator load	%	72.89%	72.04%	74.26%	73.06%

During run - blew soot	NO	YES	NO
During run - pulled bottom ash	NO	NO	NO
During run - pulled fly ash	NO	NO	NO

*NOTE: Btu integrator and Btu indicator on generators No. 6, 7. and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 15

Normal Load Run 1

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000		60,000,000	90,000,000
Coal weigh larry				
Heat output	19,450,034		38,454,934	57,904,968
% Generator load	64.83%		64.09%	64.34%
Coal input	2,206		4,220	6,426
Heat input	25,499,154		48,778,980	74,278,134
* Btu integrator				
Heat output	18,200,000		360,000	18,560,000
% Generator load	60.67%		0.60%	20.62%
Coal input	2,064		40	2,104
Heat input	23,857,776		462,360	24,320,136
* Btu indicator				
Heat output	16,320,000		20,760,000	37,080,000
% Generator load	54.40%		34.60%	41.20%
Coal input	1,851		2,278	4,129
Heat input	21,395,709		26,331,402	47,727,111
ASME PTC 4.1				
Heat output	26,700,000		38,897,000	65,597,000
% Generator load	89,00%		64.83%	72.89%
Coal input	3,010		4,250	7,260
Heat input	34,792,590		49,125,750	83,918,340
Water meter				
Heat output	26,700,000		38,897,000	65,597,000
% Generator load	899,00%		64.83%	72.89%
Coal input	3,028		4,269	7,297
Heat input	35,000,652		49,345,371	84,346,023

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 16

Normal Load Run 2

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000		60,000,000	90,000,000
Coal weigh larry				
Heat output	21,038,339		32,665,090	53,703,429
% Generator load	70.13%		54.44%	59.67%
Coal input	2,390		3,462	5,852
Heat input	27,339,210		39,601,818	66,941,028
* Btu integrator				
Heat output	19,180,000		360,000	19,540,000
% Generator load	63.93%		0.60%	21.71%
Coal input	2,179		40	2,219
Heat input	24,925,581		457,560	25,383,141
* Btu indicator				
Heat output	17,800,000		20,160,000	19,540,000
% Generator	59.33%		33.60%	42.18%
Coal input	2,022		2,222	4,244
Heat input	23,129,658		25,417,458	48,547,116
ASME PTC 4.1				
Heat output	27,300,000		37,539,000	64,839,000
% Generator load	91.00%		62.57%	72.04%
Coal input	3,085		4,121	7,206
Heat input	35,289,315		47,140,119	82,429,434
Water meter				
Heat output	27,300,000		37,539,000	64,839,000
% Generator load	91.00%		62.57%	72.04%
Coal input	3,101		4,137	7,238
Heat input	35,472,339		47,323,143	82,795,482

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

Table 17

Normal Load Run 3

	Generator No. 6	Generator No. 7	Generator No. 8	Total
Generator size	30,000,000		60,000,000	90,000,000
Coal weigh larry				
Heat output	21,093,878		34,595,759	55,689,637
% Generator load	70.31%		57.66%	61.88%
Coal input	2,400		3,820	6,220
Heat input	27,295,200		43,444,860	70,740,060
* Btu integrator				
Heat output	20,370,000		300,000	20,670,000
% Generator load	67.90%		0.50%	22.97%
Coal input	2,318		33	2,351
Heat input	26,362,614		375,309	26,737,923
* Btu indicator				
Heat output	18,240,000		20,280,000	38,520,000
% Generator	60.80%		33.80%	42.80%
Coal input	2,075		2,239	4,314
Heat input	23,598,975		25,464,147	49,063,122
ASME PTC 4.1				
Heat output	29,100,000		37,733,000	66,833,000
% Generator load	97.00%		62.89%	74.26%
Coal input	3,294		4,150	7,444
Heat input	37,462,662		47,197,950	84,660,612
Water meter				
Heat output	29,100,000		37,733,000	66,833,000
% Generator load	97.00%		62.89%	74.26%
Coal input	3,311		4,166	7,477
Heat input	37,656,003		47,379,918	85,035,921

* NOTE: Btu integrator and Btu indicator on generators No. 6, 7, and 8 have not been calibrated and resulting data does not correlate with the coal weigh larry and water meter. Therefore, this data should not be used in determining particulate emissions.

5 OPTIMUM OPERATION PROCEDURES

The following discussion summarizes guidance on optimizing the performance of both combustion and air pollution control equipment to maintain air pollution emission compliance throughout the remaining CHP life. The operational procedures are based on the combustion and emission tests described in Chapter 4.

Coal Handling and Storage

To prevent degradation of coal in outside storage piles, the piles should be no more than 10 ft high. The coal may be compacted only if a rubber tired vehicle is used; tracked vehicles will break the coal, creating an undesirable amount of fines. Potential for spontaneous combustion can also be reduced by keeping foreign material such as rags and paper out of the pile, and by sealing the pile with chemical sealants or plastic. Thermocouples can be inserted into the pile to take the coal's temperature to determine if there is a potential for fire.

The coal should be handled as little as possible to avoid segregation and creation of fines. One way to do this is to use just-in-time delivery instead of first-in, first-out. When coal is stockpiled and fired on a first-in, first-out basis, the coal being used is often a year or more old. A long-term coal pile can be established as an emergency pile that can be compacted and sealed. Coal deliveries should then be arranged so that coal can be delivered directly to the silo hoppers. This method allows the coal to be used before it has a chance to degrade and avoids costs of rotating and rebuilding coal storage piles.

Coal Quality

Stoker-fired coal must meet a fairly rigid set of specifications to burn properly. Traveling-grate spreader stokers, like those at Rickenbacker, should be provided with bituminous coal that meets the specifications shown in Table 18. The most important specifications for stoker operation are Ash Fusion Temperature and Size Distribution.

Ash fusion temperature provides an indication of the tendency of the ash in the coal to partially melt in the burning process. Most coals in the Ohio area have an ash fusion temperature lower than the flame temperature of the fuel. To avoid the possibility of the ash melting and fusing to form "clinkers," the fuel bed must burn out rapidly. This limits the time that the ash is exposed to the flame of the burning fuel, and limits the temperature of the ash to something below the fusion temperature.

To compensate for ash fusion problems, the operator must increase the amount of combustion air to an above-normal level to assure burnout of all combustible material in the fuel bed. However, this is an undesirable solution because high air flows tend to carryover fly ash into the multicyclone collectors and scrubber, and can also reduce the efficiency of those pollution control devices.

The size distribution specification provides the stoker with the proper coal sizes to obtain uniform distribution of coal across the width of the stoker. If the coal distribution over the grate area is not uniform it will cause three problems:

Table 18

Traveling Grate Spreader Stoker Coal Specifications

Specification	Value
Proximate analysis	
Moisture (M)	0.20%
Volatile Matter (VM)	30 - 40 %
Fixed Carbon (FC)	40 - 50 %
Ash	5 - 20 %
Heating value:	10,500 - 14,000 Btu/lb
Free swell index:	7 - maximum
Hemispherical temperature: (H = 1/2 W Reducing)	2,150 °F minimum
Size distribution (See Figure 17)	
Top size (1-1/4 in.)	5 %
1-1/4 in. by 3/4 in.	10 %
3/4 in. by 1/2 in.	35 %
1/2 in. by 1/4 in.	30 %
1/4 in. by No. 8	15 %
Less than No. 8	5 %

1. There will be uneven coal feed between feeders.

2. There will be an uneven porosity in the fuel bed, which will cause an uneven proportion of combustion air to coal in different areas of the grate.

3. Those areas of the fuel bed that have the larger coal sizes will require a longer burnout time, further upsetting the air-to-fuel ratio in areas of the fuel bed.

As with improper ash fusion temperature, the operator must increase the amount of combustion air to an above-normal level to assure burnout of all of the combustible material in the fuel bed.

All coal shipments should be inspected and sampled according to Defense Fuel Supply Center (DFSC) guidelines. After a coal shipment has been received and found to be correct by matching delivery papers to the current contract, the coal should be visually inspected for presence of foreign material such as slate, pyrites, trash, excessive moisture, dirt, and other undesirable material. If the coal appears to contain excessive bigs or fines, a size analysis must be made. If the coal does not meet specification, it should be rejected. Before the coal can be accepted and used, the inspector must collect a sample for chemical analysis as described in DFSC Manual 4185.1[4]

[4] *Quality Assurance Procedures for Receipt of Coal Procured Through DFSC*, DFSCM 4185.1 (Defense Fuel Supply Center [DSFC], Alexandria, VA, July 1979).

Spreader Stokers

A spreader stoker is an extremely versatile solid fuel burning apparatus. It will burn almost any solid material containing combustible matter. The proficiency with which the material is burned depends on a number of factors. The most fundamental factor in optimum spreader stoker firing is uniform fuel distribution over the entire effective grate area. Literally, this means an even proportion of coal sizes over the entire burning area.

The spreader stoker consists of two basic components: (1) the grate surface (a perforated table) on which the fuel is distributed and burned, and (2) a feeding mechanism (one or more feeders), which controls the coal flow rate and its distribution over the grate area.

Combustion controls can approximate the amount of coal that is fed into the furnace through the feeders and they can proportion the amount of combustion air fed into the furnace to that amount of coal. Unfortunately, the controls cannot determine or adjust coal distribution over the grate area. The adjustment of the stoker for coal quality variation is one of the most important duties of the plant operator.

Feeder Adjustments

Since there is more than one feeder per stoker, the operator is responsible to see that all feeders on one stoker add equal amounts of coal to maintain uniform distribution over the grate area. This is best observed by estimating the ash depth on the grate surface just before it is discharged into the ashpit.

The ash depth must be uniform across the width (laterally) of the stoker (remember that the depth of ash represents hours of coal distribution into the furnace). If the ash depth is uneven, that area of the grate with the most ash is getting too much coal. If the ash depth is uneven below the centerline of each feeder, the feeder rates must be adjusted. This is accomplished by adjusting the fuel feed control mechanism that advances or retards the fuel feed of each feeder individually with respect to the combustion control positioner.

If the ash depth is uneven between the centerline of the feeders and the spaces between feeders, the angle of the distributor paddles must be adjusted in the Riley feeders, or the rotor blades must be changed in the Detroit feeders. Without exception, this unevenness appears as too much ash along the centerline of the feeders and not enough ash between feeders. This imbalance in lateral (side to side) coal distribution is corrected by resetting the paddle angles on the Riley feeders, or by replacing the rotor blades on the Detroit feeders. This is not an adjustment made by the plant operator, but one made during maintenance periods.

Coal distribution from front to rear (longitudinally) is as important as lateral distribution. Distributing enough coal to the rear of the grate surface is a function of trajectory plate setting and paddle speed. With the trajectory plate adjusted into the furnace, the face of the paddle is nearly vertical where the coal falls off the trajectory plate. To drive coal to the rear of the furnace with these settings, the paddles must be turning at relatively high speeds. This results in the coal following a flat trajectory.

Under these conditions, coal is distributed along the length of the grate. The largest lumps have the greatest inertia and travel the farthest. Further, many of the lumps that hit the fuel bed at about the rear third of the grate tend to ricochet to the rear wall of the furnace. Finally, the high paddle speeds result in a considerable amount of the lumps not falling in front of a paddle but being tipped by a paddle. These lumps will dribble off the feeder and land on the fuel bed at the discharge end of the grate. The total effect is one of poor longitudinal fuel distribution.

With the trajectory plate adjusted out of the furnace, the face of the paddle is angled upward when it impacts the lumps of coal. With this adjustment, the coal trajectory is high and coal reaches the rear of the furnace with a much lower paddle speed. When a lump of coal impacts the fuel bed, it is traveling in a more vertical direction, which greatly reduces the tendency of the lumps to ricochet to the rear of the furnace. Finally, the slower paddle tips considerably fewer lumps and less coal dribbles off the feeders. This will produce a more even longitudinal coal distribution, and is recommended as the feeder settings.

Longitudinal coal distribution varies with coal size and surface moisture. An increase in coal size requires a reduction in paddle speed to maintain distribution. Also, an increase in surface moisture requires an increase in paddle speed to maintain distribution.

There are observation doors on each side wall of the furnace just forward of the rear wall at the firing level. Longitudinal coal distribution is determined by observing the flame pattern through these doors. Longitudinal distribution is proper when one can look at least half way across the furnace along the rear wall at the level of the doors. When looking down toward the grate surface through these doors one sees only a bright orange flame. If one sees only orange flame at the level of the door, there is too much coal being distributed along the rear of the furnace.

A second observation determines longitudinal distribution by noting the undergrate temperatures. Proper longitudinal distribution will result in the lowest possible undergrate temperatures.

A third observation will monitor the ash bed on the grate surface as it is discharged into the ashpit. Excess coal being burned at the rear of the furnace creates a tendency of the ash to begin to fuse together on the bottom of the ash bed or directly on the grate metal surface. Excess coal being burned toward the front of the furnace creates a tendency of the ash to begin to fuse together at the top of the ash bed. Both of these conditions depend on the amount of combustion air passing through the fuel bed, the size or oversize of the coal, and the ash fusion characteristics of the coal.

Grate Speed Adjustment

The grate surface is a perforated metal surface on which fuel is distributed and burned. The grate travels from the rear to the front of the furnace to carry and discharge accumulating ash into the ashpit (called "continuous ash discharge"). The speed of the grate should be determined entirely by the ash depth. Grate speed should be adjusted to maintain an absolute minimum of 3 in. of ash on the discharge end of the grate. For best stoker performance, the ash bed should be 5 to 7 in. Accordingly, grate speed will be increased when firing rate is increased, or if a coal with higher ash content is burned. The rule is very simple: Adjust the grade speed to maintain approximately 6 in. of ash on the discharge end of the grate surface at all times. (WARNING: this rule refers to 6 in. of ash bed, NOT fuel bed.)

Combustion Control

In general, the purpose of the instruments and combustion controls is to assist the plant operator. It is imperative that the operator observe the instruments and controls regularly to assure that the equipment is performing properly. Any deviation from normal operation should be noted by the operator and evaluated to determine if corrective action is necessary.

<u>Manual Operation</u>. Variations in coal size, surface moisture content, Btu, wear in the feeders, etc. will result in varying coal Btu input into the furnace for a given setting of the combustion controls. Therefore, it is normal to expect periods when the combustion controls are out of phase with regard to the Btu output of the heaters. This should be corrected by biasing the fuel feed control on each feeder. In the case of the Riley feeders this is accomplished by adjusting the coal gates. Raising the coal gate will increase coal throughput for a given combustion control setting.

On the Detroit feeders, this is accomplished by adjusting the fuel-feed mechanism. Periodically, the plant operator must note the relation of the combustion control loading against the Btu output of the heater and adjust when necessary. These two factors should be in balance with the Btu output, slightly ahead of the combustion control loading so the controls are always ready to respond to load changes.

Note that any adjustments to the stoker should be made in small increments to avoid the problem of "overcorrecting." After making an adjustment, there should be a waiting period of 15 min or more, after which another tour will determine the effects of the change.

Air/Fuel Ratio. The air in this ratio is the primary combustion air provided by the forced draft fan. After establishing that the best possible coal distribution is being maintained over the grate area, the proper or optimum air/fuel ratio is established by gradually decreasing combustion air until signs of ash fusion begin within the ash bed. At this point the air flow should be increased very slightly. With the correct coal specification, the resulting excess air should be somewhere in the order of 30 to 35 percent at high loads. This will increase sharply at low loads. Coal that does not meet the specifications for the stoker will not be able to maintain low levels of excess air.

Overfire Air. Spreader stokers normally burn at least 60 percent of the volatile matter in the coal in suspension in the furnace. To ensure complete combustion of the suspended material, adequate turbulence within the flame envelope must be maintained. This turbulence is provided by the use of high velocity jets of air at various levels in the furnace (i.e., the overfire air system). Basically, there is one row of overfire air nozzles across the rear wall about 20 in. above the grate surface. The maximum air pressure in these nozzles is about 15 in. It is recommended that this row be operated fully open for the loads normally carried. There is a row of nozzles under the feeders (two per feeder), which were intended to help drive coal dust away from the front wall and the feeder openings. The minimum air pressure in these nozzles should be about 10 in. The influence of the rear OFA is to drive the flame forward, thus causing the flame to roll and creating the necessary mixing of the combustible material. The minimum air pressure in these nozzles should be about 10 in.

One last use of the OFA system is to return fly ash from the boiler backpass to the furnace (the ash reinjection system). This system keeps this gas pass of the heater empty of fly ash so as not to interfere with the normal flow of gas over the heating surfaces of the boiler. To assure that this system is in order, the static pressure in this air manifold should be kept at over 10 inches.

Opacity Meters. The opacity meters located at the multicyclone outlets should be used to monitor the condition of the fire in the furnace. The monitors indicate the amount of fly ash present in the flue gas stream. The opacity at the outlet of the multicyclone collectors should be about 25 percent near full boiler capacity. As the load drops, this will increase because the efficiency of the unit also drops. Operators should graph the opacity, temperature and oxygen content at several boiler loads during good operating conditions to help check the day-to-day stoker operation. Careful attention to the operation of the combustion equipment will avoid the production of fly ash particles that can overload or damage air pollution control equipment.

Opacity meters are sometimes subject to erroneous readings from dust buildup on the glass shields protecting the sensors. The dust buildup will occur more frequently if the duct is under a positive pressure. Accordingly, the glass surfaces should be cleaned frequently. In addition, the meter readings can be influenced by misalignment of either the glass shields or the sensors.

Multiple Cyclone Collectors

The efficiency of multiple cyclone collectors is influenced by the velocity of the flue gas flow through the cyclones. Optimum gas velocity occurs when the pressure drop across the collector is approximately 2.5 to 3.0 in. water pressure. The pressure drop and the related gas velocity through the collector will be influenced by the total gas flow. Therefore, there will be a lower pressure drop at light firing rates, and the efficiency of the collector will drop at low firing rates. Fortunately, at low firing rates, less fly ash is carried out of the furnace because the combustion gas flow is also lower.

Poor collection efficiency can also be caused by re-entrainment of ash from the hopper area because of tube pluggage, air infiltration, and high hopper ash levels. The collector hopper ash must be pulled frequently enough to keep the ash level well below the bottom of the tubes. Tube surfaces should be checked and cleaned, if necessary, during annual maintenance.

BAHCO Wet Scrubber

The following guidance for operating the scrubber should replace the current scrubber operating procedures. The listed system conditions obtained the best particulate removal efficiencies recorded for this scrubber and should be maintained to ensure continued compliance with OEPA emission regulations.

Scrubber Inlet Static Pressure. This determines the total static pressure drop possible across the scrubber system. Initial collection of fly ash particles is partially dependent on the static pressure drops across each of the two stages. The inlet static pressure should be greater than 15 in. of water and generally in the range of 17 to 25 in. of water to maintain proper fly ash collection capability.

Second Stage Static Pressure Drop. The stage 2 static pressure drop should be less than 6 in. Higher static pressure drops increase the potential for droplet re-entrainment, counteracting any beneficial effects of stage 2 particle collection.

Fan Current. The booster fan current provides an indication of the total gas flow through the scrubber system. High gas flow rates are needed to maintain proper cyclonic action in the demister. The fan currents should be maintained above 70 amps.

Multicyclone Collection Static Pressure Drop. The static pressure drop across the common multicyclone collector provides another indication of total gas flow rate. This static pressure drop is related to the square of the gas flow rate, and to the gas density. Since the latter value is primarily a function of gas temperature and is relatively stable, the pressure drop provides a gas flow indicator. The static pressure drop should generally be above 3.4 in. of water.

First and Second Stage Weir Heights. The weirs in the first and second stage level tanks influence the quantity of liquid re-entrained in each stage, and the size distribution of these droplets. Improper weir heights can lead to either inadequate fly ash collection or excessive losses of weir. The first stage level tank weir should be maintained at approximately 10 to 12 in. below the top. The second stage level tank weir should be at 40 to 42 in. below the top.

Second Stage Seal Tank Conditions. The 1987 test program demonstrated the importance of minimizing the liquor trapped above the second stage immediately below the centrifugal vanes. When the unit is operating in an ideal state, and the seal tank remains essentially empty, slight water vapor emissions will be visible, leaving the second stage seal tank as shown in Figure 21.

Stack Appearance. The presence of a condensed "steam" plume is an indirect indication of adequate liquor recirculation flow. The lack of this plume would indicate a severe scrubber malfunction. There should be less than 5 to 10 percent opacity in the residual plume when weather conditions allow the condensed "steam" to dissipate. Proper plume appearance is shown in Figure 19 (Chapter 4) and Figure 22. There should also be very little, if any, rainout of salt-laden droplets from the stack.

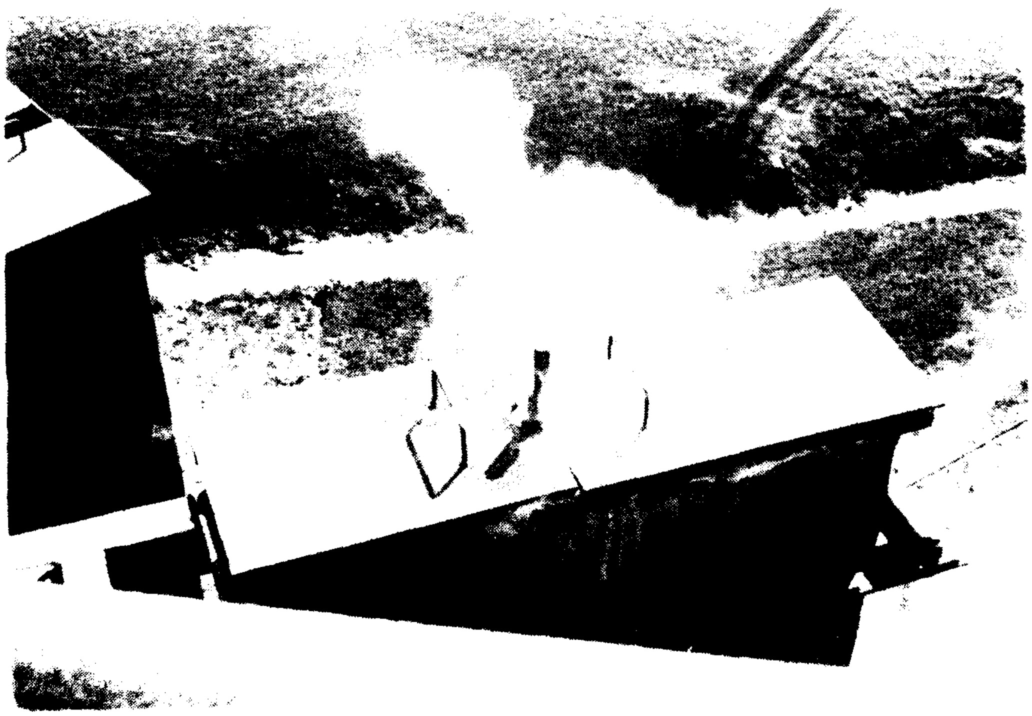


Figure 21. Steam vent leaving empty second stage drop collector.

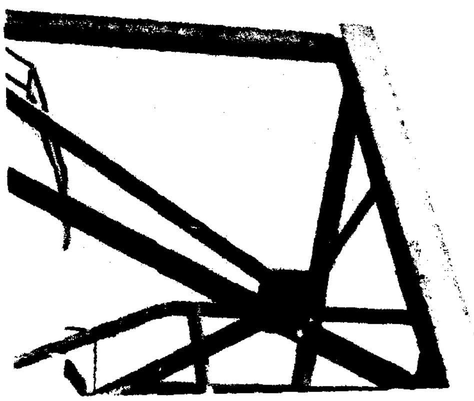


Figure 22. Dissipating water dropiet ("steam") plume with very low residual opacity.

6 CONCLUSIONS

The tests performed by PEDCo and Stilson to verify the compliance of the Rickenbacker ANGB CHP with OEPA standards were analyzed. This analysis showed that the PEDCo and Stilcon test results did not prove conclusively that the Rickenbacker ANGB central heating plant had violated particulate emission standards for the State of Ohio.

On 31 March 1987, the Rickenbacker ANGB central heating plant met Ohio EPA particulate emission standards with an average emission rate of 0.1006, lower than the Ohio EPA standard of 0.174 by a margin of 70 percent.

It is concluded that the performance procedures developed in this study will enable the Rickenbacker ANGB central heating plant to continue to meet Ohio EPA air pollution regulations as long as proper operating conditions of the plant are maintained.

METRIC CONVERSION TABLE

1 in.	=	25.4 mm
1 ft	=	0.305 m
1 mi	=	1.61 km
1 sq ft	=	0.093 m^3
1 cu ft	=	0.028 m^3
1 lb	=	0.453 kg
1 ton	=	907.1848 kg

APPENDIX A: Engineering Statements

chmidt associates, inc.
7333 FAIR OAKS ROAD / CLEVELAND, OHIO 44146 / PHONE (216) 439-7300
CONSULTING ENGINEERS

ENGINEERING STATEMENT
RICKENBACKER ANGB
STACK EMISSION SURVEY - MARCH 1986 TEST

BY: CHARLES M. SCHMIDT, PROFESSIONAL ENGINEER
OHIO REGISTRATION NO. 31532
APRIL 29, 1987

In March 1986, a series of particulate emission tests were conducted by Stilson Laboratories, Inc. on the coal-fired boilers at Rickenbacker ANGB and the results included in a report identified as:

Particulate Emissions and Sulfur Dioxide Tests
Coal-Fired High-Temperature Water Generators
For
Rickenbacker ANGB
Report No. 9658-04
Report Date: April 1986
Test Date: March 20 & 21, 1986

I have made a preliminary review of the above report. In my professional opinion the report is invalid because of the following reasons:

1. Incorrect stack diameter was used. Pages 7, 10, and 13 show a 64-inch diameter. Schmidt Associates, Inc. April 1987 report, Section III page 12 and Section V page 12 shows a 66-inch diameter stack.

2. Complete lack of proving coal heat input into boilers. Coal input calculations on pages 29 and 30 are based on the assumption that the coal auger supplies the same amount of coal (lbs.) to Boiler No. 8 every 1-1/2 minutes. (Coal density changes with coal sizing.) Coal input calculations for Boilers No. 6 and No. 7 are also based on a similar assumption.

3. A constant 17% O_2 and 2.0% CO_2 reading during the two-day test period makes the accuracy of these readings suspect. See page 3.

ENGINEERING STATEMENT CONT'D.
RICKENBACKER ANGB
STACK EMISSION SURVEY - MARCH 1986 TEST
PAGE 2

4. An emission rate calculated from a heat input based on an assumed 80% efficiency rather than a calculated efficiency. See note at bottom of page 3.

5. Federal regulations Method 3 states that an Orsat analyzer must be used to determine excess air or emission rate correction factor. Exhaust gas O_2 was measured by a Fyrite analyzer which is in violation of Federal regulations. See Stilson Laboratories, Inc. letter to Wyonne K. Morningstar, Rickenbacker ANGB dated August 1, 1986, page 2. This letter indicates the use of a Fyrite analyzer.

6. Pitot tube coefficient shown on calibration sheet that was included in letter to Wyonne K. Morningstar, Rickenbacker ANGB does not correspond to coefficients on pages 7, 10, and 13 of the report. Also, an ideal 'S' type pitot tube would have a coefficient of .84 to .85. While a .88 coefficient as shown in the report is conceivable, it is unlikely.

7. Barometric pressures shown on pages 7, 10, and 13 are too high. They were probably not corrected for elevation.

8. A static pressure of 0.0 shown on pages 7, 10, and 13 is incorrect. If flue gas is moving, it <u>has</u> a static pressure.

9. A 65.8 percent isokenetic condition for test No. 1-2 (see page 8) does not satisfy EPA Method 5 criteria. It is standard procedure for stack test personnel to reject all stack tests when one or more of the runs is not within the required isokenetic rates.

I, Charles M. Schmidt, a Professional Engineer, do set my hand and seal to the above statement which is my true opinion.

Charles M. Schmidt, P.E.

Charles M. Schmidt,
Professional Engineer, Ohio Registration No. 31532

ACKNOWLEDGEMENT

STATE OF OHIO	)	
	) ss.	CORPORATION
COUNTY OF CUYAHOGA	)	

BEFORE ME, a Notary Public in and for said County and State, personally appeared the above named Charles M. Schmidt, P.E., for Schmidt Associates, Inc., its President, who acknowledged that he did sign the foregoing instrument, and that the same is the free act and deed of said Corporation, and the free act and deed of him personally as such officer.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal at OAKWOOD, OHIO, this 29th day of APRIL, 1987.

James D. Darrow
Notary Public
My commission expires:

JAMES D. DA...
Notary Public, State of Ohio, Cuya. Cty
My Commission Expires Sept. 28, 19..

chmidt associates, inc.
7333 FAIR OAKS ROAD / CLEVELAND, OHIO 44146 / PHONE (216) 439-7300
CONSULTING ENGINEERS

ENGINEERING STATEMENT
RICKENBACKER ANGB
STACK EMISSION SURVEY - MARCH 1980 TEST

BY: CHARLES M. SCHMIDT, PROFESSIONAL ENGINEER
OHIO REGISTRATION NO. 31532
APRIL 29, 1987

In March 1980, a series of particulate emission tests were conducted by PEDCo Environmental, Inc. on the coal-fired boilers at Rickenbacker ANGB and the results included in a report identified as:

Emission Test Report
Rickenbacker Air Force Base
Volumes, I, II, II & IV
Contract No. 68-02-2811
Report Date: June 1980
Test Date: March 12 & 13, 1980

I have made a preliminary review of the above report. In my professional opinion the report is invalid because of the following reasons:

1. Incorrect stack diameter was used. See sketch in Volume I page 3-7 which shows a 64-inch diameter. Schmidt Associates, Inc. April 1987 report Section III page 12 and Section V page 12 shows a 66-inch diameter stack.

2. No calculations to verify the emission rates presented in Table 3-58, Volume I page 3-77. Values do not agree with F-Factor using 17% O_2 or 11% O_2.

3. Conflicting CO_2 and O_2 data. In Volume III page C262, Run No. R05-1, table shows an O_2 reading of 11.4% and a CO_2 reading of 7.4% while Volume III pages C-245, C-266 and C-391 show an O_2 reading of 17.6% and a CO_2 reading of 0.4%.

   Also in Volume III page C-262, Run No. R05-2, table shows an O_2 reading of 11.4% and a CO_2 reading of 7.4% while Volume III pages C-246, C-269 and C391 show an O_2 reading of 19.6% and a CO^2 reading of 0.4%.

ENGINEERING STATEMENT CONT'D.
RICKENBACKER ANGB
STACK EMISSION SURVEY - MARCH 1980 TEST
PAGE 2

4. If an 0.4% CO_2 concentration is correct, such a concentration is substantially below levels typical of coal-fired boilers. There is no attempt to recheck or evaluate this data. Also, there is no discussion of the possible reasons why CO_2 concentration on March 12th was 0.4% as compared to 8.0% on March 13th. See pages C-246 and C-247 of Volume III.

5. Limited scrubber operating data. Scrubber data was taken once per shift. Data should have been taken every 10-15 minutes during the test runs.

I, Charles M. Schmidt, a Professional Engineer, do set my hand and seal to the above statement which is my true opinion.

Charles M. Schmidt, P.E.

Charles M. Schmidt,
Professional Engineer, Ohio Registration No. 31532

ACKNOWLEDGEMENT

STATE OF OHIO)
) ss. CORPORATION
COUNTY OF CUYAHOGA)

BEFORE ME, a Notary Public in and for said County and State, personally appeared the above named Charles M. Schmidt, P.E., for Schmidt Associates, Inc., its President, who acknowledged that he did sign the foregoing instrument, and that the same is the free act and deed of said Corporation, and the free act and deed of him personnally as such officer.

IN TESTIMONY WHEREOF, I have hereunto set my hand and affixed my official seal at Oakwood, Ohio, this 29th day of April, 1987.

James D. Darrow
Notary Public
My commission expires:_______________

JAMES D. DARROW
Notary Public, State of Ohio, Cuya. Cty
My Commission Expires Sept. 25, 1990

RICHARDS ENGINEERING
2605 Tanglewood Road, Durham, N.C. 27705 919-493-2384

April 27, 1987

Mr. Charles Schmidt, P.E.
Schmidt Associates, Inc.
7333 Fair Oaks Road
Cleveland, Ohio 44146

Re: Particulate Stack Test Conducted at Rickenbacker Air National Guard Base, 1980 and 1985.

Dear Mr. Schmidt:

As you requested, I have prepared preliminary comments concerning the stack test reports for the particulate emission tests conducted at Rickenbacker Air National Guard Base in March, 1980 and in April, 1985. The 1980 tests were conducted by PEDCo Environmental, Inc., now called PEI, Inc. The 1985 test was conducted by Stilson Laboratories, Inc. It is my opinion that neither test adequately and accurately represents actual particulate emissions from the scrubber system.

The 1985 tests contained numerous errors which have probably introduced biases which lead to higher than actual emission rates. For example, during test run 2-1, the test crew reported a percent isokenetic condition of only 65%. This does not satisfy EPA Method 5 criteria which requires that test crews maintain isokinetic conditions of not less than 90% or greater than 110%. At low isokinetic rates, large particulate is preferentially captured within the probe and leads to higher than actual emission rates. It is standard procedure for stack test personnel to reject all stack tests (set of 3 runs) when one or more of the runs is not within the required isokinetic rate.

The stack test report submitted by Stilson Laboratories, Inc. did not include calibration data for the S-type pitot tube used in the test. This is of particular concern since the S-type pitot tube coefficient reported in the stack test report had a value of .88. An ideal S-type pitot tube would have a value of .84 to .85 and in the large majority of cases, actual units have coefficients slightly less than .84. While a value of .88 is conceivable, it is unlikely.

One of the most basic measurments in a stack test is the stack diameter. It should be noted that in one portion of their report, Stilson Laboratories, Inc. used a value of 64 inches while in another section they used 66. In fact, the actual diameter is 66 inches. If they used 64 inches, an error was introduced into their calculations.

I would also like to question the ORSAT results. The CO2 values of 2.0% appear vely low. Also it is highly unusual to have 3 consecutive ORSAT tests yield absolutely identical results. For these reasons, I do not believe that the Stilson Laboratories, Inc. tests accurately represented actual emissions from the scrubber.

I believe that the PEDCo stack tests are also subject to several significant errors which could have an effect on the reported emission rates. On pages C-245 and C-247, the PEDCo test crew reported effluent CO_2 levels of only 0.4%. Such a concentration is substantially below levels typical of coal fired boilers. Nowhere in their report is there any attempt to recheck or evaluate this data. Furthermore, they do not discuss previous stack tests at this site in which the CO_2 levels were generally in the range of 3 to 8%. Also, they did not discuss the possible reasons why the observed value on March 12th was 0.4% and the observed value on March 13th was 8.0%. It should be noted that the CO_2 value is a key parameter used in the calculation of emission rates.

While PEDCo does not discuss any of the possible reasons for this, there is at least one plausible explanation which can be drawn from the very limited scrubber operating data reproduced with the report. The day prior to the first emission test and during the first 2 runs on March 12th, the dissolve tank pH reached very high levels. This pH ranged from 9.4 to 11.6 during that period while values of 6 to 8 are more typical of this and other similar scrubbers. The liquor from the dissolve tank is the liquor that enters the top of the scrubber. When this value is high, the liquor pH throughout the scrubber system is high. As a slightly acidic compound in solution, CO_2 can be strongly absorbed into the liquor when the pH is high. It is likely that CO_2 absorption occured during the first two outlet particulate tests (R05-1, R05-2).

During the evening hours of March 12th a sharp reduction in the pH levels apparently occured. This probably accounts for this increase of CO_2 level by a factor of 20. Since the stack test procedure is dependent on CO_2 concentration data and presumes zero CO_2 removal in the air pollution control device, the stack tests are unrepresentative of actual emission conditions. If PEDCo had conducted the stack test 24 hours later, they probably would have obtained more representative data.

I would also like to question the stack gas temperatures of 124°F to 127°F reported by PEDCo. Those temperatures are substantially higher than the stack gas temperatures measured during other emission test programs at Rickenbacker. This strongly suggests that a significant scrubber operating problem existed at the time of the PEDCo test.

For the reasons discussed in this letter, I believe that neither of these test programs present valid particulate emission data. Considering that the particulate control system used at this facility is more sophisticated than most similar boilers, I believe that flyash emissions from this unit probably were less than other boilers which the Ohio EPA has considerd in compliance during this period.

Sincerely,

John R. Richards, Ph.D., P.E.

APPENDIX B: Field Inspection Notes

RICKENBACKER AIR NATIONAL GUARD

SYNOPSIS OF FIELD INSPECTION REPORTS
FOR
BOILERS 4, 6, 7, & 8 AND COMMON DUST COLLECTOR

1. Existing high-temperature hot water generators and encompassing stack test. See Sketch No. 01.

   A. Boiler No. 4 (30 x 10^6 Btu/Hr. Heat Output)

   This unit has burned up tube ties and tubes which have been overheated and protrude into the furnace. The refractory tile behind the tubes is in bad condition and the unit has recently developed tube leakage. This unit will not be considered as part of the stack test.

   B. Boiler No. 6 (30 x 10^6 Btu/Hr. Heat Output)

   There are seven (7) mechanical collector socket joint leaks. See enclosed inspection report, Sketch No. 6A. Air leakage from combustion air inlet duct to collector inlet. See enclosed inspection report, paragraph 1.

   Repair work for the unit is estimated at $2,950.00 per R.F. Mlasofsky and Co. Work to be completed during weeks of January 26, 1987 and February 2, 1987. Retest mechanical collector and inspection by Schmidt Associates, Inc. Repair refractory on rear seal shoes for stoker per in-house personnel week of February 2, 1987. Please see Stoker Inspection Report by J.W. Chappell.

   C. Boiler No. 7 (30 x 10^6 Btu/Hr. Heat Output)

   Air leakage from combustion air inlet duct to collector inlet. Please see enclosed inspection report, paragraph 1. Four (4) mechanical collector tubes requiring replacement and one (1) tube leakage at clean gas tube sheet. See enclosed inspection report, Sketch No. 7B. Repair work for the unit is estimated at $2,950.00 per R.F. Mlasofsky and Co. Work to be completed during weeks of January 26, 1987 and February 2, 1987. Retest mechanical collector and inspection by Schmidt Associates, Inc.

   D. Boiler No. 8 (60 x 10^6 Btu/Hr. Heat Output)

   There are eight (8) mechanical collector socket joint leaks. See enclosed inspection report, Sketch No. 8A. Repair work for unit is estimated at $600.00 per R.F. Mlasofsky and Co. Work to be completed during weeks of January 26 1987 and February 2, 1987. Retest mechanical collector and inspection by Schmidt Associates, Inc.

E. Patch up expansion joint just before the common collector and any other sources of leakage in common breeching. Repair work per in-house personnel during week of February 2 1987. Retest common breeching and inspection by Schmidt Associates, Inc.

F. Repair casing leakage on all boilers. Repair work per in-house personnel during week of February 2, 1987.

Additional work to be completed prior to stack testing:

A. Install a total of five (5) test ports for Boilers No. 4, No. 6, and No. 7. and common collector. Work estimated at $400.00 per R.F. Mlasofsky and Co. to be completed during week of February 2, 1987.

B. Mount three (3) opacity meter brackets on existing brackets. Work estimated at $450.00 per R.F. Mlasofsky and Co. to be completed during week of February 2, 1987.

C. Repair two (2) collector tube gasket leaks for the common dust collector. This work is covered under previous contract with R.F. Mlasofsky and Co. and is to be completed during week of January 26, 1987 or February 2, 1987.

Although Boiler No. 4 <u>will not</u> be included as part of the stack test, there is repair work which must be completed on the unit in order to achieve a standby status. This work includes repair of two (2) areas of leakage at the dirty gas tube sheet, repair of one (1) socket joint leak, and repair of collector inlet breeching. Please see enclosed inspection report. Work is estimated at $3,150.00 per R.F. Mlasofsky and Co. and is to be completed during week of February 2, 1987. Repair work for tube leakage will be performed in late February or early March of 1987 under a separate contract.

The makeup air stack at the far east end of the common breeching located on the roof has a great deal of corrosion at the base. The stack poses a threat to the roof, adjacent equipment and plant personnel. It is not needed for plant operation and will be removed. Work for removal of the stack is estimated at $2,500.00 per R.F. Mlasofsky and Co., which is to be completed at the discretion of base personnel.

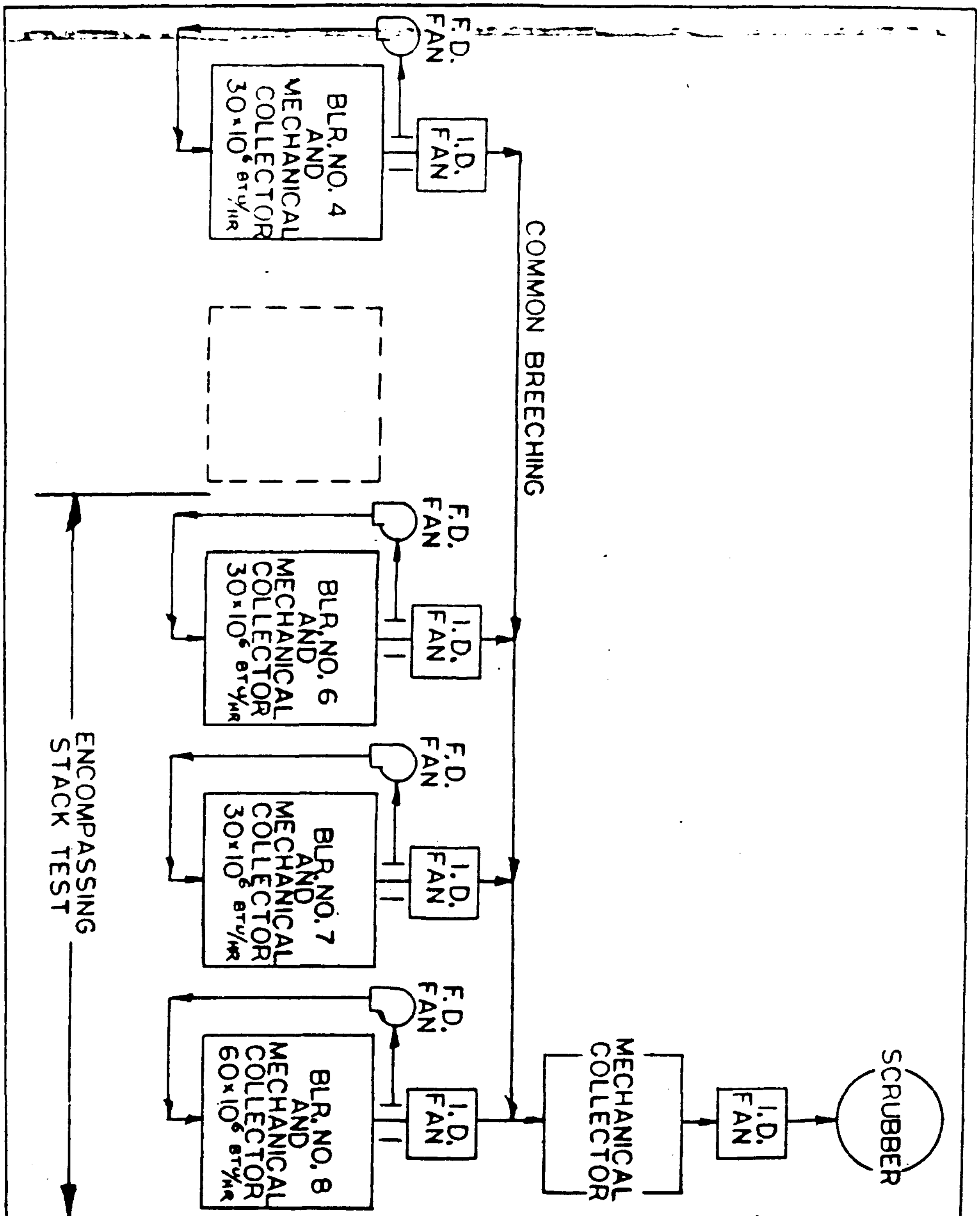
John B. Gostich

John B. Gostich

ps

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY ________ DATE ________ SHEET NO. ____ OF ____
CHKD. BY ________ DATE ________ JOB NO. 86-120-11
SUBJECT RICKENBACKER ANGB
PLANT LAYOUT



SKETCH NO. 01

RICKENBACKER AIR NATIONAL GUARD

SUMMARY OF INSPECTION RESULTS
FOR
BOILERS NO. 8, 7, 6, & 4
AND
COMMON DUST COLLECTOR

Results from field inspection of boilers and emission control equipment at the Central Heating Plant are as follows:

1. Common Dust Collector

   a) All 108 collector tubes required replacement.

   b) Collector hopper and dirty gas tube sheet required seal welding.

2. Boiler No. 4

   a) Seven (7) collector tubes worn from fly ash erosion. No replacement required).

   b) Corrosion at dirty gas inlet breeching.

   c) Extensive tube warpage and refractory tile damage.

   d) Additional refractory damage on front wall and ceiling.

   e) Leakage at dirty gas tube sheet and one (1) socket joint.

   f) Leakage at various areas of boiler casing.

3. Boiler No. 6

   a) Six (6) collector tubes worn from fly ash erosion. No replacement required.

   b) Seven (7) socket joint leaks.

   c) Leakage at various areas of boiler casing.

   d) Corrosion at dirty gas inlet breeching.

4. Boiler No. 7

a) Four (4) collector tubes requiring replacement.

b) Corrosion at dirty gas inlet breeching.

c) Tube warpage of right and left sidewalls.

d) Refractory tile damage of rear wall.

e) Extensive refractory damage of front wall.

f) Leakage at clean gas tube sheet for one (1) tube.

5. Boiler No. 8

a) Sixty (60) collector tubes worn from fly ash erosion. No replacement required.

b) Considerable slagging of both sidewalls and rear wall.

c) Slight tube warpage.

d) Eight (8) socket joint leaks.

e) Leakage at various areas of boiler casing.

Some of the repair work required to prepare the Heating Plant for State of Ohio EPA compliance testing has already been performed by an outside contractor and in-house personnel. Additional work required for preparation of the EPA compliance testing is as follows:

1. Repair the two (2) gasket leaks at the common dust collector.

2. Patch up the expansion joint just before the common collector and any sources of leakage in common breeching.

3. Patch up dirty gas inlet breeching for Boilers No. 7, 6, & 4.

4. Repair dirty gas tube sheet leakage and socket joint leak for Boiler No. 4.

5. Repair socket joint leaks for Boiler No. 6.

6. Replace four (4) collector tubes and reweld tube at clean gas tube sheet for Boiler No. 7.

7. Repair socket joint leaks for Boiler No. 8.

8 Repair casing leaks on all boilers.

RICKENBACKER AIR NATIONAL GUARD
COLUMBUS, OHIO

STOKER INSPECTION REPORT
J.W. CHAPPELL

November 2, 1986 thru November 7, 1986

Sunday, November 2, 1986

En route from Easley, South Carolina to Columbus, Ohio - In Lexington, Kentucky

Monday, November 3, 1986

En route from Lexington to Columbus and the job site. Arrived at job site 11:30 A.M. at which time I met with Mr. Jerry Gaietto the Power Plant Superintendent. Had to get power on stokers, feeders, etc., and run grates around so opening in grates would be at front, ready for inspection first thing Tuesday morning. Also, to remove three grate racks and clips from one (1) grate which had no racks removed.

Tuesday, November 4, 1986

Unit No. 8 - Detroit Stoker - Inspected the furnace area. The tubes looked good except for a thin scale which should flake off after firing a few days. There was some slag on roof tubes at boiler outlet, but not enough to cause any problem unless more builds up rapidly.

Refractory around feeder front good, except under the arch, where there are four (4) tile brick missing. This tile arch brick should be replaced as soon as possible.

Rear grate seal tuyeres are O.K. After replacing eight, one (1) seal tuyere about half burned off; one (1) more partly burned. These should be replaced as soon as spares can be ordered as there are no more spares on hand.

Grates are good, front and rear air seals look good (what could be seen of them without any clips removed). They are pushing Mr. Gaietto to close up unit and light it off tonight. We did not have the time to remove any clips, but I could see part of the seals between grate sections at front and rear, and the seals look good. Grate slide rails are good; grates show no sign of any bad condition.

Feeder partly renewed; all blades (paddles) on Feeders No. 1 and No. 2, left to right facing feeders. Feeder No. 3 paddles are O.K., except for a little wear. Replaced feed box (pusher box) on each feeder and also spill plates.

They installed the feed boxes (stoker length) with bolts in the incorrect bolt hole. Mr. J. Gaietto and I placed the bolts and blocks in the correct position. These could not be left in the incorrect position as it would have caused the feeder to feed too much coal, unless you would have had to have this to make a full load, but I do not think so. In any event, these can be changed while operating if more coal feed is needed at the top end. However, the way we set them is the proper position for good fuel distribution over the load range. Also adjusted the spill plates at the right starting position. More adjustment may be needed after getting a fire in the unit.

Checked all feeders over and adjusted as good as could be done until the fire was started. They are supposed to light off the unit tonight; however, when I left the job around 6:00 p.m. they had a lot of work of washing out the scrubbers, closing up the unit, etc.

It is my hope to get started on Riley Unit No. 7 tomorrow...

Wednesday, November 5, 1986

Started a fire in the Detroit Unit No. 8 around 10:00 a.m. and began sending hot water out through the Base. Personnel happy about this as they were getting a little cold. Firing light this afternoon (about 2" to 3" of ash bed). Fuel distribution looks very good at this time and feeder operating very good so far.

Riley Unit No. 7 - Inspection

Wednesday, November 5, 1986

Furnace - Boiler tubes look good. There is some thin scale which is flaking off; however, feel this is due to washing of the furnace done sometime back. Overall the tubes are in good condition fire sides; hope the water sides are in as good a shape as the fire sides.

Furnace Refractory - The furnace refractory behind tubes looks good. Bad part is the feeder front, and this will cause no problem this year unless some of the refractory is poked off by knocking off slag. The right corner should have been partly knocked out and patched up, but I think this part will last through the winter.

There is some smooth slag over the front wall and one the feeder front but not too bad. Under feeder arch is good. One (1) tile brick out, but they have replaced with refractory which is O.K. The feeder front refractory should be replaced next summer. O.F.A. nozzles are good. Also, under feeder O.F.A. nozzles are O.K.

Grates - Grate clips are good. Also, the chains, drive and idler shaft, holding collars are good. Shaft bearings are good. Although we did not remove the bearing caps, could tell the bearing inserts are good by checking the bearing seals real good. There was no time nor manpower to remove the bearing caps, which does take a lot of time.

Grate racks are in good condition; ledge seal plates, side wall air seal tuyeres in good condition; rear over grate seal shoes good. Replaced these and filled shoes with refractory. Front air seals good; top air seal, end seals are good. Also, in between rails, the seals are good. Idler shaft jack screws good; idler shaft discs are good; drive shaft sprockets are good, and rack end clearance to side seals good.

Some skid shoes have been replaced. The center chain skid shoes are in bad condition. This center skid rail is a single skid. Other two (2) skid rails are doubles. The center chain skid shoes should be replaced by next summer or the racks will begin to ride on the skid rail and wear out in the racks. Also, these will start hanging up and cause severe trouble. Will order new parts for the grates, rather, Mr. Caietto says that he will order the new parts. Getting the parts numbers and writing them down will take up the better part of the day. Some skid shoe cuts on the top air seals from this center chain skid shoes, but this is no problem at this time. They should however be renewed next summer.

Feeders No. 1 and No. 2

Feeders, gear housing, distributor rotors good. Paddles are O.K., but have some wear on them. Trajectory plates, pusher boxes, coal gates and chains, feeder air swept cutoff plates, and feeder open side seals are all good.

Feeder deflector air tuyeres are in bad condition. The nose of the tuyeres is burned off approximately 2 inches on both feeders. This will be O.K. for the winter, but should be renewed the first possible chance they get. Feeder paddles are set to Riley engineering standards; however, on this small furnace, I am sure they would need some more fine adjustment on operation of this unit at top load or near top load. I ran the feeder to check them out and also to check out the feed rate control assembly. The feeder control rate is not right with the combustion control drive. I then adjusted the feed rate assembly with the control drive to give the pusher box its maximum stroke of 1 inch, with the control drive at full travel. This is setting the feeder feed rate hand pointer with the feed rate automatic feed rate pointer. You can offset the feed rate from the automatic pointer with hand control pointer and see this by just looking at the feed rate assembly pointer.

Before this adjustment was made, and this is the proper way they should be set up, no one could know how much feed rate they had. Will also check the other two (2) units (No. 6 and No. 4). Will start on Unit No. 6 tomorrow, grate, feeders, etc...

Riley No. 6 Unit - Inspection

Thursday, November 6, 1986

Completed inspection on Unit No. 6 today. Unit No. 7 and No. 6 are just about the same. I could take the two (2) units and make one (1) good unit.

Furnace - Tubes look good. They have been washed down and are pretty clean. Refractory is O.K. Part of the feeder front refractory has been patched, and a good job was done. New casting shields on the side wall tubes; rear nose arch casting shields are O.K., and front wall brick is good. Also side wall tile brick behind tubes looks very good. The two (2) soot blowers (what I can see of them) are O.K.

Grates - Idler shaft O.K. Shaft disc is O.K. but worn down some. Shaft bearings show no sign of bad wear. Shaft collars are O.K. Grate clips and shaft jack screws are good. Rear grate over-seal shoes burned some on the ends, but the protecting refractory on the shoes is just about gone. With new refractory on the seal shoes, they would be O.K. for some time. As of now, however, they need seal shoes with refractory installed on them, or install refractory on the old seal shoes.

These over-grate rear seal shoes are a must on these one-air-zone grate stokers in order to seal the F.D. air and force the air up through the fuel bed, not to pass under the seals into the furnace. To have a good fuel burn-out, these rear air seal shoes must seal good.

Air-cool ledge seals on both sides of the grate good. Skid shoes are good on this grate. Some are worn down. Approximately 5% need replacing but no need to renew the skid shoes unless the skid rails are renewed. The skid rails are bad. Top air seals at front are cut down bad from the skid shoes due to the skid rails being worn down so much. These skid rails carry the grate and fuel bed weight.

I think they can get through the winter as is but, for the test runs, I am not so sure.

The grate chains and grate clips are good. Under feeder arch tile brick good. Front intermediate air seals are good (eight (8) air seals). Drive shaft and shaft bearings seem to be good. Drive shaft sprockets O.K.; teeth worn down some, but will not hurt anything for awhile. Also, these sprockets can be reversed to get double wear out of them.

~~I do not know the status on these units.~~ They say they will close them down in about three (3) years. If so, or not, there is a lot of work needed to be done on these units to make them last for three (3) years. Maybe the tests you are planning to run will rule on what to do about the grates, feeders, etc., mostly the grates...like the skid rails, top air seals, rear over-grate seal shoes. Also, more good work on the refractory around the feeders.

I adjusted the feeder feed rate control mechanism to the combustion control drive like I did not Unit No. 7. This set the feeder pusher box to stroke from minimum to maximum stroke with the automatic control drive. Maximum pusher box stroke is 15/16" and minimum stroke is 5/16" on automatic. You can bias the hand feed pointer away from the automatic if needed, but should not be advanced ahead of the automatic pointer when in automatic mode. If so, the control drive, if went to full open, would break the feed rate lever in the feed rate box and the feeder would stop. Bias below will not hurt anything except cut down the coal feed.

Riley Unit No. 4 - Inspection

Friday, November 7, 1986

Furnace - Tubes are in good condition except some rear and side wall tubes are bowed inward slightly. This will not hurt them unless they get worse.

Shield casting on side wall tubes in fair condition, but should be replaced in the near future. The shield casting protects the wall tubes from grate level up about 2 feet.

Front wall brick is not too good. It is all in place, but looks as though the brick has lost its heat value. Also, most of the brick is covered with slag. It should last for a good while yet. Feeder front refractory is covered with slag, but the slag is smooth all across the front and solid. This is O.K., but may cause more fuel to be burned. Under feeder arch tile brick is O.K.

Grates - All over-rear grate seal shoes need replacing <u>now</u>. They are burned up on the furnace end. Also, the over seal shoes support channels are broken up. These will have to be replaced along with the seal shoes.

Air-cool side ledge seals are O.K. Idler shaft and shaft bearings O.K. Idler shaft discs are cut down some, but will be O.K. for some time.

Under grate (rear) temperature wire (2) looks O.K., but I question if properly installed. Jack screws are O.K. Skid rails are worn down a good bit, but will do for the winter. Some chain links are slightly stretched, but will be O.K. Grate clips are good.

Skid shoes are pretty bad. Approximately 70% of the skid shoes should be replaced soon. All skid shoes on center chain need replaced soon.

The front top air seals are cut bad from the old worn out skid shoes. Seals next to and in between rails are in bad condition. Intermediate air seals are good. Drive shaft bearings and idler shaft bearings should be replaced next summer. I am sure the bearing inserts are just about gone, although the bearing seals show no sign. The grate and furnace have been water washed and it is difficult to see real clearly at the bearing seals; however, you know they have been there a long time.

The drive shaft sprocket teeth are worn down a great deal. These sprockets can however be reversed and you have new wearing surface.

Feeders -- Two (2) feeders on Unit No. 4 not in good operating condition at all. Pusher boxes have too much lost motion in the stroke, with #2 being the worst. It only has 10/16" of stroke which should be 15/16" or 1". #1 feeder is near. These feeders need new arm pins and rollers so that the pusher box rocker shaft can make the pusher boxes go the full stroke. Paddle and shaft hubs not installed properly. I straightened the hubs up and set the paddles correctly. Some of the paddles were jammed up to each other. I was unable to get to setting the feeder feed rate control to the automatic control on this unit. However, a gentlemen who Mr. Gaietto had working with me on this can do this, but they will have to get parts first.

The feeder tuyeres are also burned up on this unit. Nose of tuyeres burned up approximately 1-1/2" to 2". Air swept cutoff plate castings are good. Coal gates, trasectory plates, pusher boxes and distributor rotor all O.K. Completed inspection of the units today (November 7, 1986).

Intend to spend some time tomorrow with Mr. Gaietto going over the spare parts he will need to place these units in good operating condition plus the work he will have to do.

J.W. Chappell

RICKENBACKER AIR NATIONAL GUARD

FIELD INSPECTION REPORT
BOILER NO. 4

A visual inspection of the Mechanical Collector for Boiler No. 4 was performed on October 30, 1986. The inspection revealed seven (7) worn, dirty tubes. (See tube sheet layout on Sketch 4D, Sheet 4 of 4, for identification). These tubes are not worn extensively and should last the three (3) additional years the heating plant will remain in operation. The dirty gas inlet breeching wall has various areas of corrosion across from the clean gas tubes and above both access doors. (See Sketch 4A, Sheet 1 of 4. These were found during the same inspection period.

The breeching was designed with the idea of increasing boiler efficiency by utilizing the hot flue gases coming from the boiler to preheat the outside air the F.D. fan is supplying to the boiler for combustion. However, what is actually happening is the outside air is cooling the flue gases to below the dew point temperature, resulting in the accumulation of deposits of sulfuric acid, ultimately corroding those areas of the breeching. Although some of these areas have been patched, corrosion will continue to be a problem due to the inherent nature of the design which is typical for Boilers No. 7, No. 6, and No. 4, each of which have similar corrosion problems.

This corrosion accounts for the fact that, at certain times, the operator is unable to obtain sufficient induced draft. The outside air that is drawn through the corroded areas of the breeching reduces the amount of flue gases entering the dirty gas inlet of the dust collector, resulting in inadequate [illegible] through the boiler furnace.

Further inspection and testing were performed during the period of November [illegible], [illegible] and 26th of 1986. These inspections and tests included visual inspection of furnace area which included front wall arches and stoker inlet, right side, left side, and rear tube walls and smoke bomb testing of boiler [illegible] and mechanical collector.

The right side, left side and rear tube walls have extensive warpage, with the most severe warpage located in the left tube wall. The tile between the tubes and the boiler casing is buckled, separated and broken away in various areas of the right and left side walls. The tube warpage and tile buckling are documented on sketches and accompanying comments enclosed with this report.

The following are comments from visual inspection of the left side tube wall. Refer to Sketch 4B, Sheet 2 of 4, for location of numbered comments:

No.	Comment
1	Tubes 9 thru 14 are warped by 3" at midspan.
2	Tubes 36, 37, & 38 are warped by 1/2" at bottom. Just above refractory tile.
3	Tubes 44 thru 47 are warped by 1/2" at bottom. Just above refractory tile.
4	Tube 48 is warped by 3" at bottom.
5	Tile behind tubes is separated by 1/4" at indicated areas.
6	Tile behind tubes buckled outward by 2 to 3 inches.
7	1'-0" sq. area x 2" deep of tile broken away.
8	Tile behind tubes buckled outward by 1 to 2 inches.
9	Brick around door loose.

The following are comments from visual inspection of the right side tube wall. Please refer to Sketch 4C, Sheet 3 of 4, for location of numbered comments:

No.	Comment
1	Tubes 10 and 11 are warped by 1/2" just above refractory.
2	Tile behind tubes in these areas are buckled outward by 2 to 3 inches.
3	Open crack in tile behind tubes.
4	Tile behind tubes is separated by 1/4" at indicated areas.

The rear wall has 58 tubes which, for clarification purposes, have been numbered 1 thru 58 beginning at the left side wall with number 1 and ending with number 58 at the right side wall.

Tube numbers 1 thru 29 are bowed inward by a maximum of 1-1/2" at the bottom 1/3 of each tube.

The front wall arch sections just above both stoker inlet areas are eroding away and the deflection plates for both feeders are burned up. There are numerous areas of the front wall that have been patched, and the right and left sides of the wall have various vertical cracks.

Refractory at the ceiling appears to be breaking apart. There are several areas where approximately 6" square chunks of refractory have broken loose. This condition exists mainly towards the rear wall.

The boiler was placed under 4" W.G. pressure and physically checked for any leakage in the boiler casing and dust collector.

The dirty gas tube sheet has two (2) areas of leakage. Please see Sketch 4D on Sheet 4 of 4. Air is leaking through a small gap between the edge of the tube sheet and the hopper walls where the seal weld has broken. These areas should be rewelded. There is also one (1) additional leak through a socket joint at one of the dirty tubes. Please see Sketch 4D, Sheet 4 of 4, for identification of tube.

The following areas of the boiler casing leaked during testing:

1 Air is leaking through an old furnace draft port located at top of furnace just below the ash valve.

2 Casing at front of left side wall header (area where tubes extend through casing).

3 Lower middle inspection port on left side of boiler has bad latch and does not close.

4 Casing around tube Nos. 29 thru 42 on left side wall header.

5 Rear door on left side of boiler leaks through lower portion of frame.

6 Casing at front and rear of left side wall header. Generating section of boiler.

7 Lower rear inspection door on left side of boiler leaks through seams in both sides of door.

8 Casing at front and rear of right side wall header. Generating section of boiler.

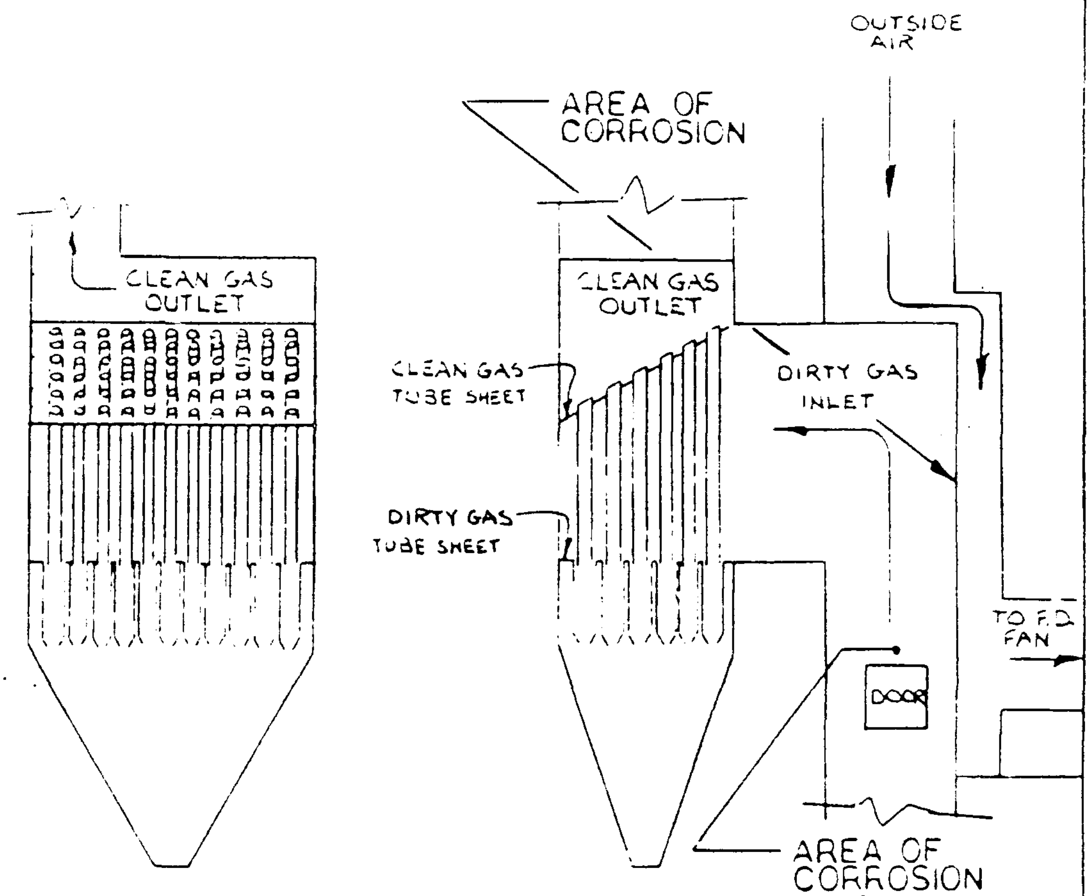
9 Casing on right side of boiler leaks through two (2) areas where casing stiffener channels are located. The first leak is located on a vertical sitffener channel. Air is leaking through two (2) bolt holes on the flange of the channel located just above the header. The second leak is located at the intersection of a vetical length of approximately 2" wide bar stock with the lowest horizontal stiffener channel.

10 Casing at front of right side wall header. (Area where tubes extend throuch casing).

11 Upper and lower ash pit doors leak through the gaskets.

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY ______ DATE ______ SHEET NO. ____ OF ____
CHKD. BY ______ DATE ______ JOB NO. ______
SUBJECT RICKENBACKER ANG
BOILER NO. 4 MECH. COLLECTOR



VIEW FACING FRONT OF BOILER

SIDE VIEW

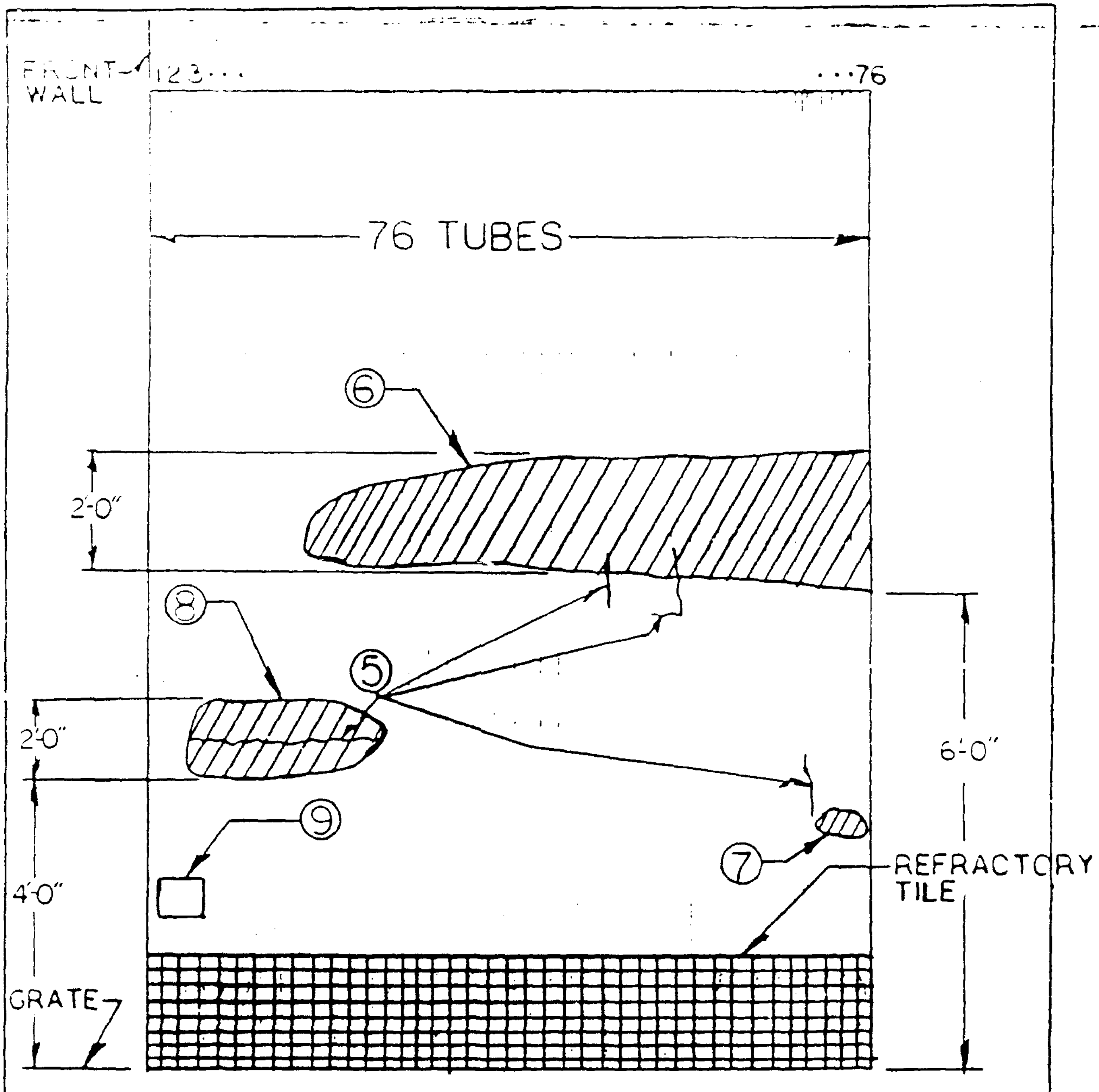
BOILERS NO. 7, 6, & 4
MECHANICAL DUST COLLECTOR

SKETCH NO. 4A

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JBG DATE
CHKD. BY DATE
SUBJECT RICKENBACKER ANG
BOILER NO. 4

SHEET NO. 2 OF 4
JOB NO. 86-120-11



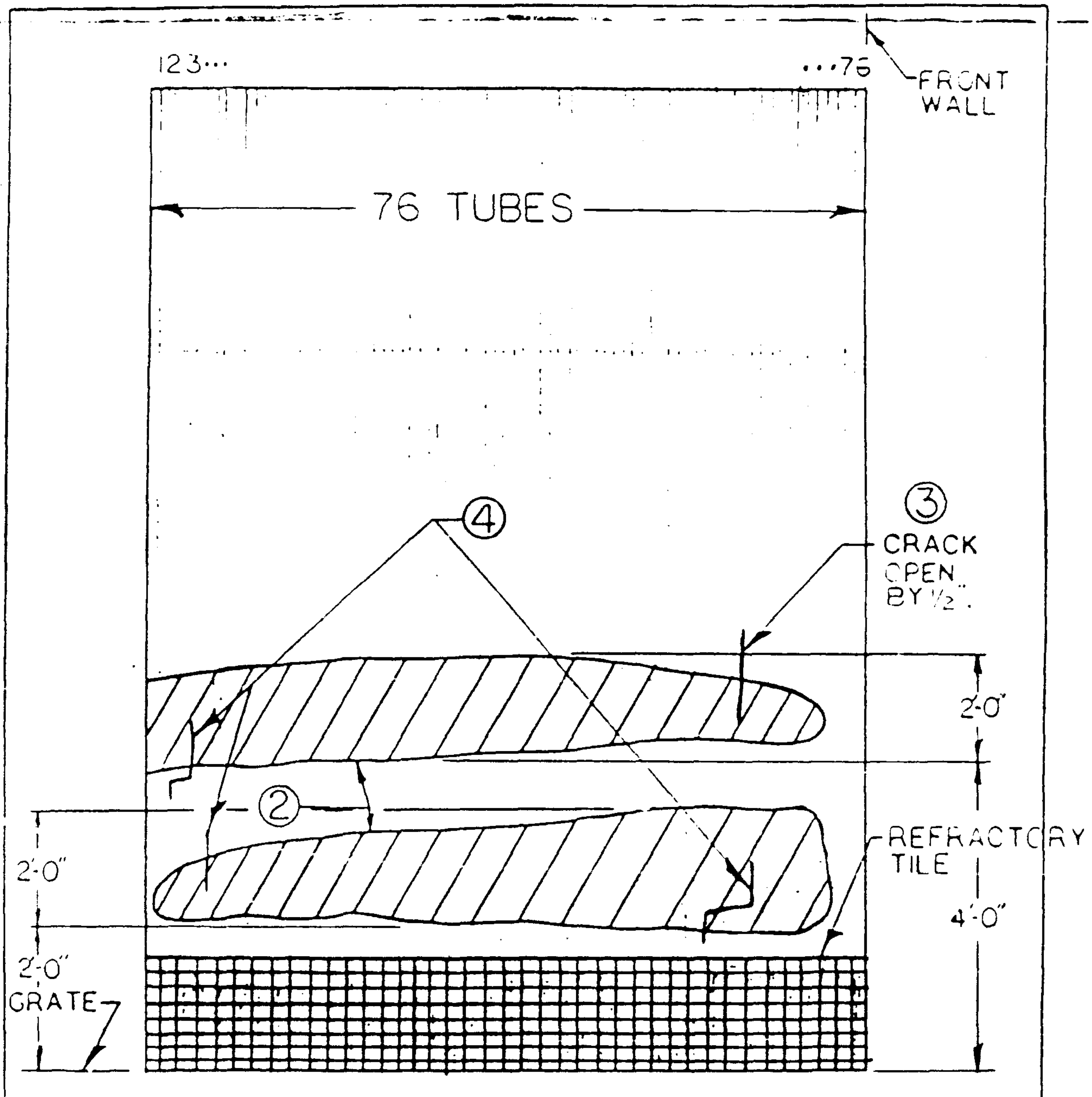
LEFT SIDE WALL

SKETCH NO 4B

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JBG DATE
CHKD. BY DATE
SUBJECT RICKENBACKER ANG
BOILER NO. 4

SHEET NO. 3 OF 4
JOB NO. 86-120-11

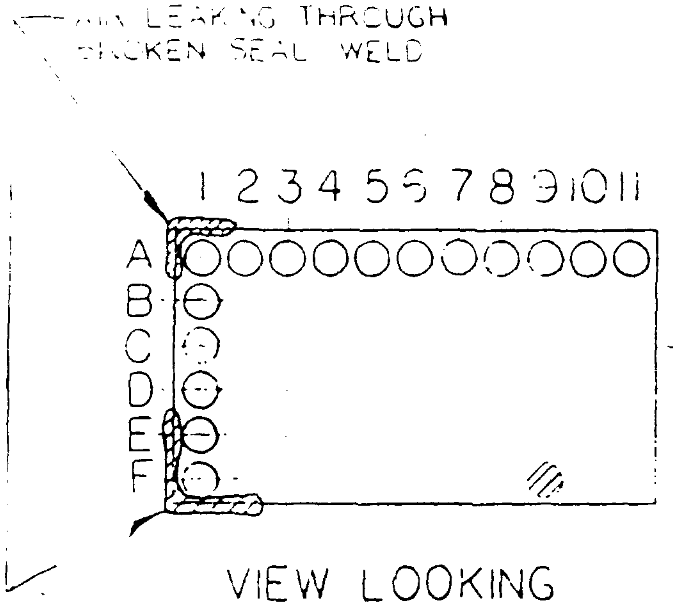


RIGHT SIDE WALL

SKETCH NO 4C

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JIBG DATE ______ SHEET NO. 4 OF 4
CHKD. BY ______ DATE ______ JOB NO 56-12C-11
SUBJECT RICKENBACKER ANG
BOILER NO. 4 MECH. COLLECTOR



VIEW LOOKING
DOWN FACING
BOILER FRONTS

TUBE SHEET LAYOUT

TUBES THAT ARE WORN:
(NO REPLACEMENT NEEDED)
B5
D2
E2, E6, E10
F6, F9

TUBES THAT LEAK AT
SOCKET JOINT ▨:
F9

SKETCH NO 4D

RICKENBACKER AIR NATIONAL GUARD

FIELD INSPECTION REPORT
BOILER NO. 6

A visual inspection of the Mechanical Dust Collector for Boiler No. 6 was performed on October 30, 1986. The inspection revealed four (4) dirty tubes that are slightly worn due to fly ash erosion. These tube will not need to be replaced. Please see Sketch 6A on Sheet 1 of 1 for identification of these tubes. The dirty gas inlet breeching wall has various areas of corrosion across from the clean gas tubes and above both access doors. Please refer to the inspection report for Boiler No. 4 for a detailed explanation of the above mentioned corrosion.

Further inspections and tests were performed during the period of January 5, 6, 7 and 8, 1987. These inspections and tests included visual inspection of the furnace area which included front wall arches and stoker inlet, right side, left side, and rear tube walls, and smoke bomb testing of boiler casing and mechanical collector.

The boiler was recently retubed and there is no sign of tube warpage.

The refractory tile behind the tubes of the rear wall has a vertical crack (not open) located at midsection and spanning the entire height of the wall.

The deflection plates above both feeder openings are burned up. There are also various deflection plates located at grate level on both sides of the boiler which are burned up.

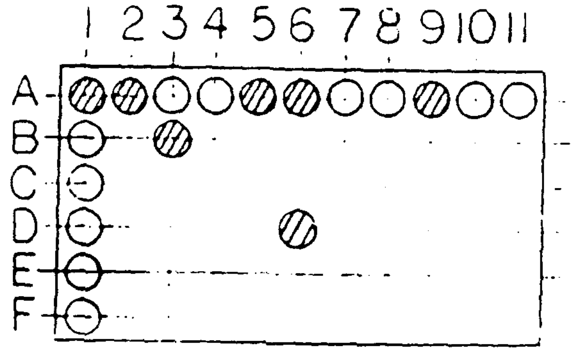
Smoke bomb testing of the dust collector revealed seven (7) joint leaks. Please see Sketch 6A on Sheet 1 of 1 for identification of these tubes.

The following areas of the boiler casing leaked during testing:

1. Front and rear end of header cover on right side of boiler.
2. Header cover around blowdown connection on right side of boiler.
3. Front and rear end of header cover on left side of boiler.
4. At vertical stiffener channel located at midsection of left side of boiler. Air leaks through channel web to casing steel connection located just above header.
5. Leak through bolt hole in casing at front of left side of boiler, just above header.

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JBG DATE ____ SHEET NO. 1 OF 1
CHKD. BY ____ DATE ____ JOB NO. 86-120-11
SUBJECT RICKENBACKER ANG
BLR. NO. 6 MECH. COLLECTOR



VIEW LOOKING
DOWN FACING
BOILER FRONT

TUBE SHEET LAYOUT

LEGEND

: TUBE LEAKS AT JOINT

WORN TUBES:
(NO REPLACEMENT NEEDED)

D5
E11
F10, F11

SKETCH NO6A

FIELD INSPECTION REPORT
BOILER NO. 7

A visual inspection of the Mechanical Dust Collector for Boiler No. 7 was performed on October 30, 1986. The inspection revealed four (4) dirty tubes that will require replacement. See tube sheet layout on Sketch 7B, Sheet 2 of 2, for identification. The dirty gas inlet breeching wall has various areas of corrosion across from the clean gas tubes and above both access doors. Please refer to the inspection report for Boiler No. 4 for a detailed explanation of the above mentioned corrosion.

Further inspection and testing was performed during the period of January 5, 6, 7, and 8, 1987. These inspections and tests included visual inspection of furnace area, which included front wall arches and stoker inlet, right side, left side, and rear tube walls, and smoke bomb testing of the Mechanical Dust Collector. Testing for boiler casing leaks will be conducted at a later date.

Tubes on the right sidewall are warped outward by a maximum of 3 inches. Please see Sketch 7A, Sheet 1 of 2, for location of affected area. This warpage also occurs at the same location for the left sidewall, but for a maximum of 1/2 inch.

The tile behind the tubes in the rear wall has a vertical crack which spans the entire height of the wall. The crack, which is located at midsection, is separated by 1/4 inch and gouged out by 1 inch on either side.

Refractory at the front wall of the boiler is breaking up and falling apart at several areas of the wall. The first area is located at the top of the refractory where this refractory is pushed out by 6 inches at midsection of the wall for a length of approximately 3'-0". Remaining refractory at either side of the buckled area is breaking up, with small areas having already fallen out. The second area where refractory is breaking up is at both corners of the wall. Affected areas span the full height of the wall and show signs of numerous patchwork at the lower portion of the wall. Refractory at the arches and around the feeders has various vertical cracks, also showing signs of numerous patchwork. The deflection plates above both feeder openings are burned up.

Smoke bomb testing of the Dust Collector revealed that one (1) tube is leaking through a creaked weld at the clean gas tube sheet. This tube is identified on the tube sheet layout on Sketch 7B, Sheet 2 of 2.

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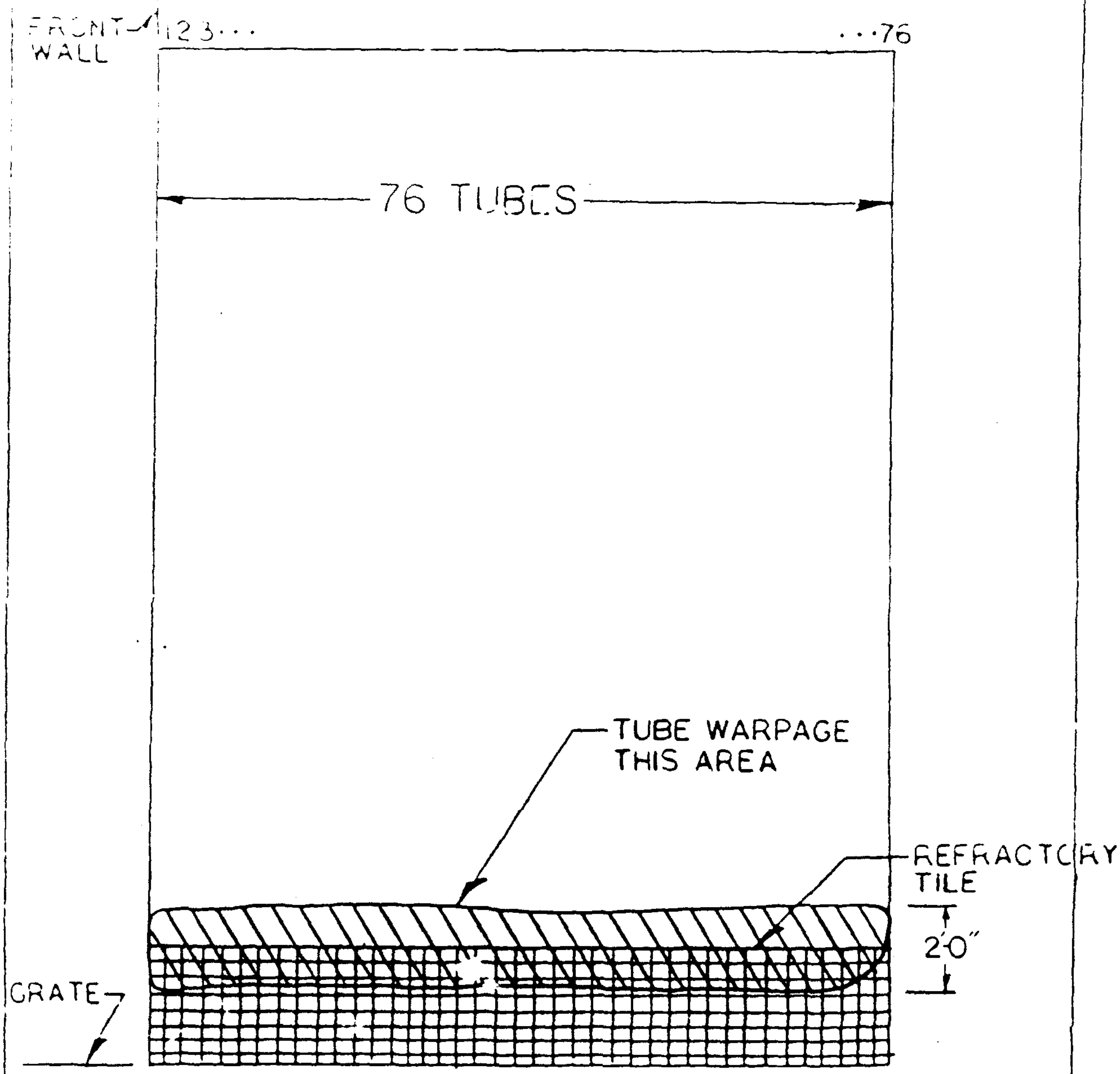
BY JBG DATE ______ SHEET NO. 1 OF 2
CHKD. BY ______ DATE ______ JOB NO. 86-12C-11
SUBJECT RICKENBACKER ANG
BOILER NO. 7



RIGHT SIDE WALL

SKETCH NO 7A

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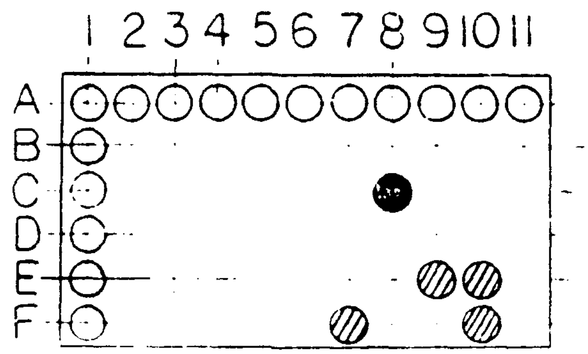
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JBG DATE ______ SHEET NO. 2 OF 2
CHKD. BY ______ DATE ______ JOB NO. 86-120-11
SUBJECT RICKENBACKER ANG
BLR. NO. 7 MECH. COLLECTOR



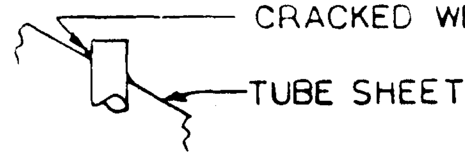
VIEW LOOKING
DOWN FACING
BOILER FRONT

TUBE SHEET LAYOUT

LEGEND

: TUBE REQUIRES REPLACEMENT

: TUBE LEAKS THROUGH WELD AT CLEAN GAS TUBE SHEET



SKETCH NO 7B

RICKENBACKER AIR NATIONAL GUARD

FIELD INSPECTION REPORT
BOILER NO. 8

A visual inspection of the Mechanical Dust Collector for Boiler No. 8 was performed on October 29, 1986. The inspection revealed sixty (60) dirty tubes showing wear from fly ash erosion. These tubes will not require replacement, since the plant will only remain operational for three (3) additional years.

Further inspections and tests were performed during the period of November 24, 25, and 26 of 1986, including visual inspection of furnace area which encompassed front wall arches and stoker inlet, right side, left side, and rear tube walls, and smoke bomb testing of boiler casing and mechanical collector.

Visual inspection of furnace area revealed considerable slagging on both sidewalls and rear wall, with extension of the slagging into the area of the first pass. The boiler casing at the area of the last pass shows signs of incurring extreme heat. This indicates that the flame is extending well into the areas of the boiler passes. This condition was corrected by J.W. Chappel during inspection of the stokers.

There was also slight slagging of the front wall around the overfire air nozzles and the area of the front wall underneath the feeders is missing five (5) firebricks.

The right and left sidewalls have seventy-two (72) tubes which, for clarification purposes, have been numbered 1 thru 72, with #1 beginning at the front wall and ending with #72 at the rear wall.

Tubes numbers 43 thru 72 of the right sidewall and tube numbers 42, 58 and 59 of the left sidewall have slight warpage.

The boiler was placed under 4" W.G. pressure and the casing and mechanical collector were checked for leakage. There are eight (8) dirty tubes that leak at the socket joint. Please see Sketch 8A, Sheet 1 of 1, for identification of these tubes.

The following areas of boiler casing leaked during testing:

1. Front door on left side of boiler leaks through door gasket.
2. Middle door on right side of boiler leaks through door gasket.
3. Cover at both ends of rear header leaks.
4. Middle door on left side of boiler leaks through door gasket.
5. Front door on left side of boiler leaks through door gasket.

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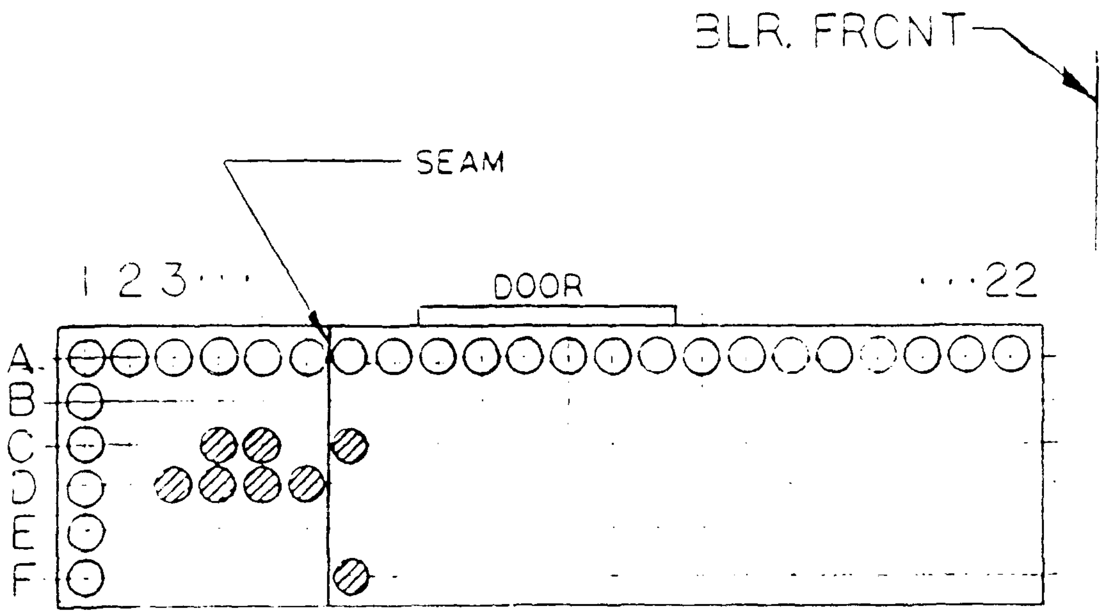
BY JBG DATE ____ SHEET NO. 1 OF 1
CHKD. BY ____ DATE ____ JOB NO. 86-120-11
SUBJECT RICKENBACKER ANG
BLR. NO. 8 MECH. COLLECTOR



VIEW LOOKING DOWN

TUBE SHEET LAYOUT

TUBES THAT ARE WORN:
(NO REPLACEMENT REQUIRED)

A13, A15, A17, A19, A20
B9, B10, B11, B12, B16, B17, B18, B19, B20
C7, C9, C10, C11, C12, C14, C16, C17, C19
D1, D4, D7, D8, D9, D10, D11, D12 - D22
E2, E7, E8, E9, E11, E12, E13, E14, E15, E18, E19, E21, E22
F7, F8, F9, F10, F11, F13, F14, F15, F16, F17, F18, F19, F20

TUBES THAT LEAK AT
SOCKET JOINT ⊘:

C4, C5, C7
D3, D4, D5, D6
F7

SKETCH NO8A

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RICKENBACKER AIR NATIONAL GUARD

FIELD INSPECTION REPORT
COMMON DUST COLLECTOR

The Common Dust Collector was visually inspected on November 6, 1986. Sixty-two (62) dirty tubes worn from fly ash erosion were found, with sixteen (16) having holes of various sizes ranging from 1/8" diameter to 1" diameter. The inspection also revealed that the seam on the dirty gas tube sheet between Rows 5 and 6 and various areas of the hopper were not seal welded. Please see attached tube sheet layout, Sketch 1, Sheet 1 of 1, for location of seam.

All One Hundred and Eight (108) collector tubes were replaced by an outside contractor and the seal welding was done by in-house personnel.

The Dust Collector was then smoke bomb tested on January 6, 1987, to determine whether the contractor properly sealed all of the tubes to the dirty gas tube sheet and whether there were any additional leaks not anticipated during visual inspection.

The smoke bomb test revealed that two (2) of the collector tubes were improperly installed and leaking through the gasket of the dirty gas tube sheet. Also a great deal of leakage was noticed coming from the expansion joint at the dirty gas inlet breeching just prior to the collector. Once these areas of leakage are repaired, the collector will be ready for EPA emissions testing.

Attached is a Dust Collector Inspection Report which will provide you with inspection and test results for the individual components of the dust collector.

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DUST COLLECTOR INSPECTION REPORT
PAGE 2

6. Shiny dust patterns — Yes ________ No ___x____

Location: ____

7. Flyash buildup — Yes ___x____ No ________

Location: ____

8. Flyash within collector tubes — Yes ___x____ No ________

Tube Nos: Approx. 10% of Collector Tubes

9. Flyash buildup in dirty gas inlet and breeching — Yes ___x____ No ________

10. Flyash buildup on clean gas tube sheet — Yes ___x____ No ________

11. Condition of:

Guide or Recovery Vanes (Zurn) — Good ___x____ Bad ________

Description: Some Plugged

Inlet Ramos or Spinners (U.O.P.) — Good ___x____ Bad ________

Description: ____

Spirocone or Tricone (Western) — Good ________ Bad ________

Description: N/A

12. Access door condition

a. Lower hopper door(s)

Gasket(s) — Good ________ Bad ___x____

Locking Device — Good ___x____ Bad ________

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DUST COLLECTOR INSPECTION REPORT
PAGE 3

b. Dirty gas inlet door(s) (No Door Opening was cut out)

Gasket(s) Good _______ Bad _______

Locking Device Good _______ Bad _______

c. Clean gas inlet door(s)

Gasket(s) Good _______ Bad _______

Locking Device Good _______ Bad _______

13. Ash valve(s) seal Good ___x___ Bad _______

Note: Not all ash valves visible for inspection.

14. Comments and/or Recommendations: Replace all 108 Collector tubes and seal weld seam on dirty gas tube sheet between Rows 5 & 6 and [redacted] various areas of Hopper. Replace gasket on hopper Access Door and ~~install doors on dirty gas inlet and clean gas inlet~~

B. Test Results After Installation of Plugs (SMOKE BOMB) Date of Test: January 6, 1987

1. Dirty gas tube sheet leakage Yes _______ No ___x___
(where tube sheet is welded to collector casing)

Location: _______________________________

2. Cast iron tube flange leakage Yes ___x___ No _______
(where cast iron tube is bolted to dirty gas tubesheet)

Tube Nos: B2 and D4 (See attached Tube Sheet Layout)

3. Clean gas tube sheet leakage Yes _______ No ___x___
(where tube sheet is welded to collector casing)

Location: _______________________________

4. Clean gas tube leakage Yes _______ No ___x___
(where tube is bolted or welded to clean gas tube sheet)

Tube Nos: _______________________________

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5. Joint between cast iron socket and steel clean gas tube leakage Yes ________ No ________

Tube Nos: N/A

6. Hopper seam leakage Yes ________ No x

Location: ________

7. Expansion joints leakage Yes x No ________

Location: All dirty gas inlet breeching

8. Ash valve(s) seal leakage Yes ________ No x

9. Access door leakage

a. Lower hopper door(s) Yes ________ No x

Location: ________

b. Dirty gas inlet door(s) Yes ________ No x

Location: ________

COMMENTS AND/OR RECOMMENDATIONS: Contractor should repair the collector tube leaks. In-house personnel should repair breeching expansion joint leak and any other areas of possible leakage at the common breeching

NOTE: See attached dust collector tube sheet layout for tube numbers and location.

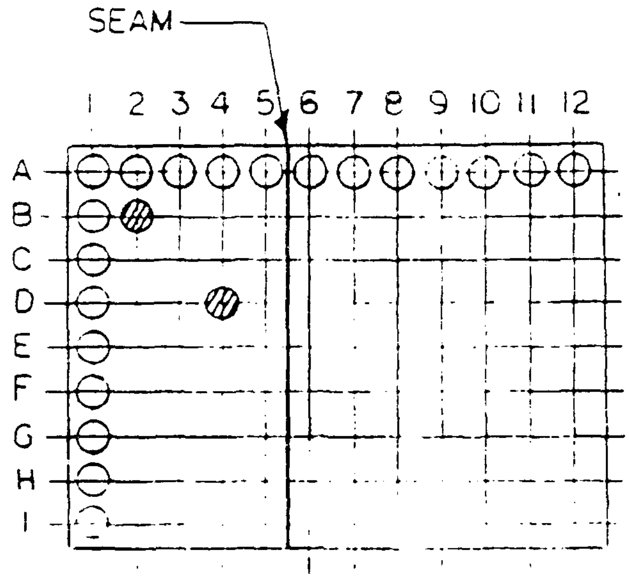
INSPECTOR(S): J. Gostich & J. Salley

Date Approved: ________

SCHMIDT ASSOCIATES
CONSULTING ENGINEERS
CLEVELAND, OHIO

BY JBG DATE
CHKD. BY DATE
SUBJECT RICKENBACKER ANG COMMON DUST COLLECTOR

SHEET NO. 1 OF 1
JOB NO. 86-120-11



DIRTY GAS TUBE SHEET LAYOUT

VIEW LOOKING DN
FACING SCRUBBER

LEGEND

: TUBE LEAKS THROUGH GASKET.

SKETCH NO. 1

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